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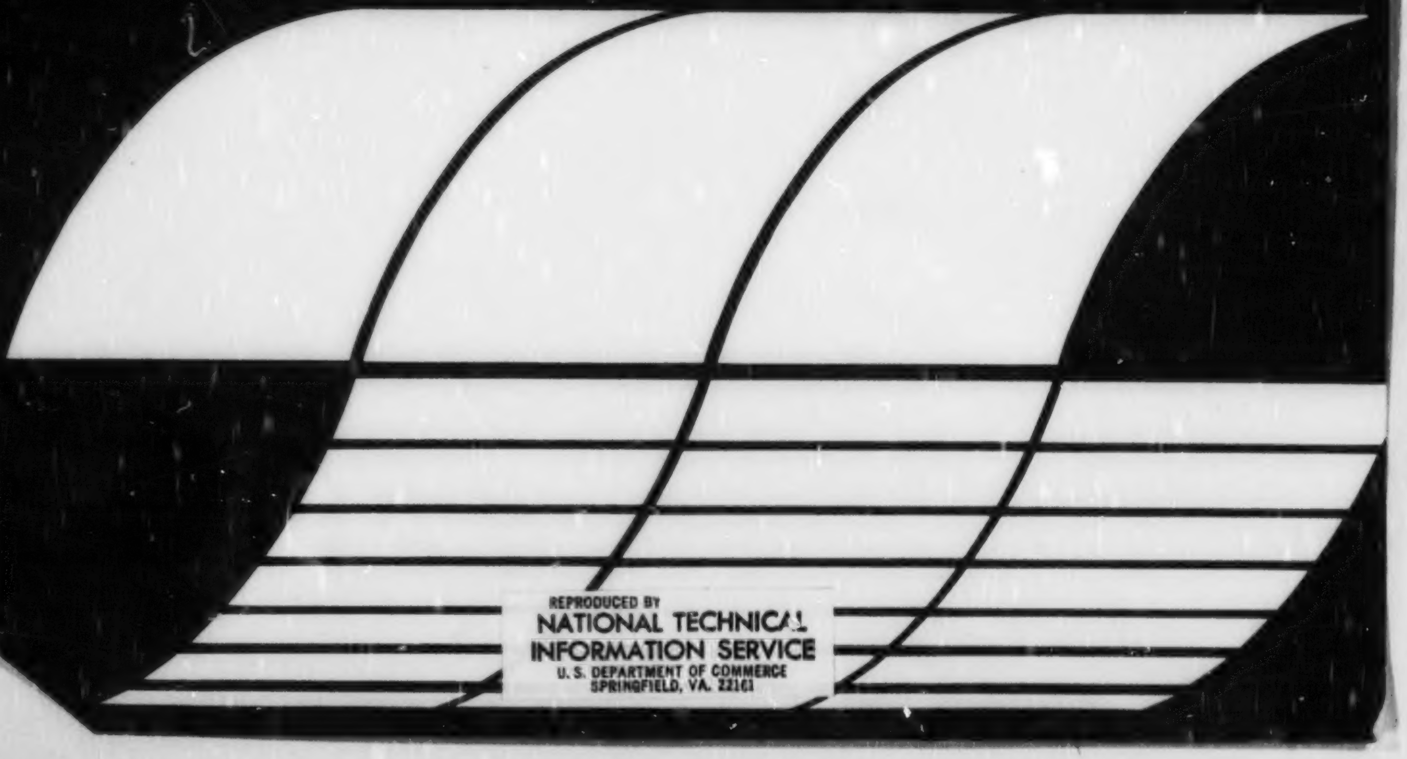

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This publication presents the U.S. Environmental Protection Agency's Office of Energy, Minerals, & Industry's interagency coal cleaning research, development and demonstration program. This report consists of the papers presented in the two sessions, Coal Preparation of Pollution Control, of the Fourth National Conference on Energy and the Environment (October 5-6, 1976, Cincinnati, Ohio). The first session (section I of the publication) is concerned with the physical chemical and geochemical aspects of coal including resource distribution and availability. The second session (section II of the publication) centers on the cleaning technology, both physical and chemical, that is advancing towards commercialization in cooperation with or under sponsorship from the Government.

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COAL

from coal sessions of
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Energy and the Environment
Cincinnati, Ohio

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FOREWORD

This report is composed of papers presented at two sessions of the Fourth National Conference on Energy and the Environment at Cincinnati, Ohio on October 6, 1976. They represent the Environmental Protection Agency's interagency program for coal cleaning.

Because environmental standards affect the development of a technology for utilizing much of the nation's coal, the most desirable means for minimizing pollution from coal is being sought. Pollutants can be controlled: prior to combustion by systems for cleaning (processing) coal of undesirable constituents; during combustion, as for example, by using fluidized bed combustion techniques; after combustion by processing effluents and emissions, as for example, gas flue cleaning; or by combinations of these various methods depending on the properties of various coals in conjunction with their energy generating systems.

The purpose of these sessions, and this report, is to spot-light coal cleaning technology as the primary means for reducing and controlling the undesirable emissions resulting from the combustion of coal.

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William N. McCarthy Jr.
Washington, D.C.
October 1976

PART I. PHYSICAL/RESOURCE ASPECTS

THE NEED FOR COAL CLEANING

Mark D. Levine
Robert E. Fullen
William N. McCarthy, Jr.
Gary J. Foley

This presentation is entitled "The Need for Coal Cleaning." The talk could also have been entitled "Is There a Need for Coal Cleaning?" or "What are the Circumstances Under Which There is a Need for Coal Cleaning?"

Figure 1.1.1 raises four issues concerning the need for coal cleaning. The first is: how will a near-term increase in coal use affect the environment? The second issue is: can policies be adopted that will minimize adverse environmental impacts and increase coal use? Thirdly, is there a shortage of low sulfur coal, and is there likely to be a shortage in the near future? And finally, can coal cleaning reduce the overall environmental impacts of coal use?

Many of the presentations we will hear in the sessions today will treat these issues. This particular talk will focus on the last two of the issues concerning the availability of low sulfur coal and the potential for coal cleaning to increase supply of low sulfur coal, thus reducing emissions of sulfur to the environment.

To address these issues, we have performed projections of supply and demand for low sulfur coal between 1975 and 1985. As shown in Figure 1.1.2, the projections are based on several straightforward assumptions. These assumptions are:

- The demand projections for coal are based on the Federal Energy Administration reference case demand projection for coal. The demand for low sulfur coal was derived from projections for total coal demand.
- The supply projections are derived from industry and Environmental Protection Agency sources.
- The sulfur content of future coal supplies is estimated from the results of tests carried out over the past decade by the U.S. Bureau of Mines.
- We assumed that all new energy facilities will be in compliance with air quality standards.

Figure 1.1.3 presents the sources for the projections. The demand projection is primarily based on the Federal Energy Administration's "National Energy Outlook" for 1976. The supply projection is derived from industry sources, including the Keystone Coal Industry Manual, the National Coal Association, and analyses performed by the Policy Planning Division of the Environmental Protection Agency. The disaggregation of coal supply by sulfur content was accomplished using data from tests performed by the U.S. Bureau of Mines (with support from EPA pass through funds). This information has recently been published in a report entitled "Sulfur Reduction Potential of Coals of the United States." Finally, assumptions about the use of scrubbers in new coal-fired power plants were made using EPA and industry survey results.

Figure 1.1.4 summarizes our two demand cases for low sulfur coal. Demand Case 1, derived from the Federal Energy Administration's "National Energy Outlook" projection of coal demand by sector, assumed that 60 percent of new coal-fired power plants will use scrubbers to remove sulfur, in conformance with the results of the EPA and industry surveys. Demand Case 2 is different from Demand Case 1 in the assumption that only 35 percent of new coal-fired power plants will use scrubbers for sulfur removal. Thus, Demand Case 2 represents a greater demand for low sulfur coal because of the reduced use of scrubbers.

Figure 1.1.5 illustrates the demand projections for Demand Cases 1 and 2. This figure shows a small projected increase in demand for low sulfur coal in the industrial, residential/commercial, and export sectors of the economy. The substantial increase in demand for low sulfur coal (over 60 percent from 1975 to 1985) is due to increasing use of low sulfur coal by electric utilities. The lower portion of the graph for electric utilities shows the utility demand for low sulfur coal for Demand Case 1 (that is, for the case in which 60 percent of new coal-fired plants employ scrubbers). The entire cross-hatched area for electric utilities shows the demand for low sulfur coal in Demand Case 2 (for which 35 percent of new coal-fired plants are assumed to use scrubbers). Demand Case 2 requires substantially greater amounts of low sulfur coal than Demand Case 1: approximately 1 quadrillion Btu (50 million tons) per year in 1980 and 2 quadrillion Btu (100 million tons) per year in 1985. The unshaded portion of the graph shows the increased demand for higher sulfur coal by electric utilities. The small area in the upper right hand corner of the figure is the projected demand for coal by synthetic fuel facilities. The major point of Figure 1.1.5 is that the two demand cases represent a significant increase in demand for low sulfur coal between now and 1985, and the increase is due almost entirely to the use of coal by electric utilities.

Figure 1.1.6 summarizes the two supply cases that are used in this analysis. Supply Case 1, based on industry projections, indicates that 85 percent of the growth in low sulfur coal production is projected to take place in the western states. These projections result in annual growth of Western coal production of 35 percent between 1975 and 1980, and of 15 percent per year in Western coal production from 1980 to 1985. Supply Case 2 assumes that these high growth rates of Western coal production are not attained. The objective of Supply Case 2 is to assess the impacts of a high, but reduced, growth rate of Western coal. Supply Case 2 still has a substantial growth rate for Western coal production: 20 percent annual production increase from 1975 to 1980 and 10 percent annual production increase from 1980 to 1985.

Figure 1.1.7 presents Supply Cases 1 and 2. This figure clearly indicates that almost all of the increased production of low sulfur coal is derived from the growth in Western coal production. Even for Supply Case 2, in which Western coal production growth rates are reduced, almost all of the growth in low sulfur coal is derived from the West. There is a slight increase in the production of Southern Appalachian coal of low sulfur content. No increase in production of low sulfur coal in Northern Appalachia, Alabama or the Midwest is projected between now and 1985.

Figure 1.1.8 provides a comparison of the supply and demand projections for low sulfur coal. The graph in the upper left hand corner is a comparison of Demand Case 1 and Supply Case 1. This is the case for which we have assumed that 60 percent of new coal-fired power plants use scrubbers and that Western coal development occurs at the higher rate. We note that there could be a very small deficit of low sulfur coal until 1978 and a small surplus of low sulfur coal after 1978. The basic conclusion from this graph is that for a scenario consisting of Demand Case 1 and Supply Case 1, supply and demand for low sulfur coal are well balanced between the present and 1985.

The graph in the upper right of Figure 1.1.8 compares Demand Case 1 with Supply Case 2, in which the rate of increase of Western coal production is somewhat reduced. This graph shows an increasing deficit of low sulfur coal, particularly after 1980, and growing to over 2 quadrillion Btu per year (or over 100 million tons) by 1985.

Demand Case 2, in which we assume that only 35 percent of new coal-fired power plants employ scrubbers also results in substantial deficits of low sulfur coal, as shown by the two graphs at the bottom of Figure 1.1.8. The combination of Demand Case 2 and Supply Case 1 results in a deficit of low sulfur coal of approximately 2 quadrillion Btu per year by 1985. The worst case is the combination of Demand Case 2 (lower scrubber use) and Supply Case 2 (lower Western coal growth). In this case, there is a potential deficit of low sulfur coal amounting to over 4 quadrillion Btu per year by 1985, or more than 200 million tons of low sulfur coal per year.

Figure 1.1.9 summarizes the conclusions from the two supply projections and the two demand projections. We conclude that if Western coal production grows at projected rates and if 60 percent of new coal-fired power plants install scrubbers, there will be no substantial shortage of low sulfur coal to meet EPA emission standards between 1975 and 1985. However, if the growth rates of Western coal production are reduced by about one third, then our projections indicate an annual shortage of low sulfur coal of slightly less than 1 quadrillion Btu in 1980 and almost 2.5 quadrillion Btu, or 120 million tons per year, in 1985. Furthermore, if only 35 percent of new coal-fired power plants install scrubbers, then an additional shortage of low sulfur coal of approximately 1 quadrillion Btu in 1980 and 2 quadrillion Btu could occur in 1985.

The results of this analysis lead us into a discussion of the need for coal cleaning. As shown in Figure 1.1.10, the potential shortage of low sulfur coal between the present and 1985 leads us to ask the question to which the remainder of this talk is devoted: Can the use of coal cleaning increase the supply of low sulfur coal to meet this potential deficit of low sulfur coal?

To understand the future role of coal cleaning it is useful to look at past trends. Figure 1.1.11 shows quantities of U.S. coal that have been mechanically cleaned between 1965 and 1973. Both on a percentage basis, and also in absolute amounts, coal cleaning has seen decreasing use over the last decade. This figure does not tell the whole story, since it does not indicate the degree to which the coal has been cleaned. Nonetheless, the trend is clear: in the past decade, the use of coal cleaning devices for coal has decreased.

To understand the potential of coal cleaning to help meet any future shortage of low sulfur coal, it is useful to note the amount of coal that can meet EPA's sulfur emission standards before and after cleaning. This information is presented in Figure 1.1.12. The information represents an average of the samples that have been studied by the U.S. Bureau of Mines. We make the assumption that this average figure is indicative of the sulfur content of the coal reserves in the regions. For Alabama, the eastern Midwest and western Midwest, the percentage of coal meeting EPA sulfur emission standards is not greatly changed through the use of coal cleaning. However, for the Northern Appalachia, Southern Appalachia, and Western coal regions the percentage of coal that meets sulfur emission standards can be increased significantly through the use of coal cleaning. The percentage of coal that meets these standards increases from 4 percent to 12 percent in Northern Appalachia; from 35 percent to 50 percent in Southern Appalachia; and from 70 percent to 94 percent in the West. Of these regions, Southern Appalachia and the West represent large quantities of coal and thus have the greatest potential for using coal cleaning to reduce potential future deficits of low sulfur coal. Using the information presented in Figure 1.1.12 and the supply and demand projections for low sulfur coal, we have analyzed several strategies for increasing the availability of low sulfur coal. The results of this analysis are shown in Figure 1.1.13. Figure 1.1.13a indicates that the full application of coal cleaning technologies could result in an additional 0.5 quadrillion Btu (25 million tons) per year of low sulfur coal for Supply Case 2 in 1985 and 1.2 quadrillion Btu (60 million tons) per year for Supply Case 1 in 1985. Thus, without changing the projected mix of coal supply, a growth of coal cleaning capacity alone could contribute in significant measure to a reduction in potential shortages of low sulfur coal.

A second strategy to increase production of low sulfur coal is to combine full application of coal cleaning with an increased growth in Southern Appalachian coal. If the growth rate of Southern Appalachian coal were increased from current projections of 2 percent per year to a growth rate of 6 percent to 10 percent per year and coal cleaning were used to reduce the sulfur content, then a substantial increase in low sulfur coal supply would be obtained. For a 6 percent annual growth in the production of Southern Appalachian coal, over 1 quadrillion Btu (50 million tons) per year of additional low sulfur coal could result in 1985. A 10 percent annual growth rate of Southern Appalachian coal could yield as much as 2.5 quadrillion Btu (125 million tons) per year of low sulfur coal in 1985, with full use of coal cleaning.

Figure 1.1.13c compares the results of the two Supply and two Demand Cases already analyzed with a new supply strategy that combines a 10 percent annual growth rate in the production of Southern Appalachian coal with increased use of coal cleaning.

This analysis makes clear that coal cleaning offers one approach that can significantly reduce the likelihood of shortages of low sulfur coal in the next decade and thereafter.

- HOW WILL A NEAR-TERM INCREASE IN COAL USE AFFECT THE ENVIRONMENT ?
- CAN POLICIES BE ADOPTED THAT WILL MINIMIZE ADVERSE ENVIRONMENTAL IMPACTS OF INCREASED COAL USE ?
- IS THERE A SHORTAGE OF LOW SULFUR COAL ?
- CAN COAL CLEANING REDUCE OVERALL ENVIRONMENTAL IMPACTS OF COAL USE ?

THE NEED FOR COAL CLEANING: ISSUES

Figure 1.1.1

- DEMAND PROJECTIONS USE FEA REFERENCE CASE
- SUPPLY PROJECTIONS ARE DERIVED FROM INDUSTRY AND EPA SOURCES
- THE AVERAGE SULFUR CONTENT OF COAL DEPOSITS IS ACCURATELY REPRESENTED BY U.S.B.M. SAMPLES
- COMPLIANCE WITH AIR QUALITY STANDARDS FOR ALL NEW FACILITIES

METHOD OF APPROACH: ASSUMPTIONS BEHIND COAL FORECASTS

Figure 1.1.2

METHOD OF APPROACH: SOURCES

1. DEMAND PROJECTION
    - FEA NATIONAL ENERGY OUTLOOK (1976)–PROJECTED COAL DEMAND BY SECTOR
2. SUPPLY PROJECTION
    - KEYSTONE COAL INDUSTRY MANUAL (1975)
    - OTHER INDUSTRY SOURCES
    - EPA ANALYSES
3. SUPPLY/DEMAND ANALYSIS BY SULFUR CONTENT
    - SULFUR REDUCTION POTENTIAL OF THE COALS OF THE UNITED STATES, EPA AND U. S. B. M. (APRIL 1976)
    - USE OF SCRUBBERS BY UTILITIES FROM EPA SURVEYS (1976)

SUPPLY/DEMAND FORECASTS FOR LOW SULFUR COAL 1977-1985

Figure 1.1.3

DEMAND CASE 1:

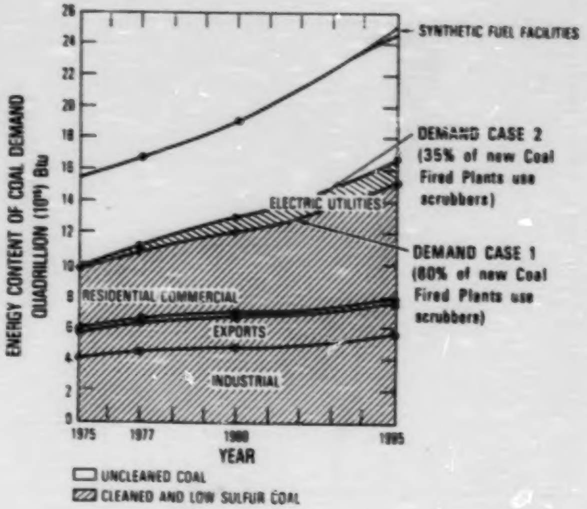
- FEA NATIONAL OUTLOOK PROJECTION OF COAL DEMAND BY SECTOR
- 80% OF NEW COAL FIRED POWER PLANTS USE SCRUBBERS TO REMOVE SULFUR

DEMAND CASE 2:

- FEA DEMAND PROJECTION
- 35% OF NEW COAL FIRED POWER PLANTS USE SCRUBBERS TO REMOVE SULFUR

LOW SULFUR COAL DEMAND CASES

Figure 1.1.4



U. S. LOW SULFUR COAL DEMAND FORECAST: CASES 1 AND 2

Figure 1.1.5

LOW SULFUR ≤ 0.6 LB SULFUR/10^6 Btu

SUPPLY CASE 1:

- INDUSTRY PROJECTIONS WITH 85% OF GROWTH OF LOW SULFUR COAL PRODUCTION IN WESTERN STATES
- RESULTS IN 35% ANNUAL GROWTH IN WESTERN COAL PRODUCTION (1975–1980) AND 15% ANNUAL GROWTH IN WESTERN COAL PRODUCTION (1980–1985)

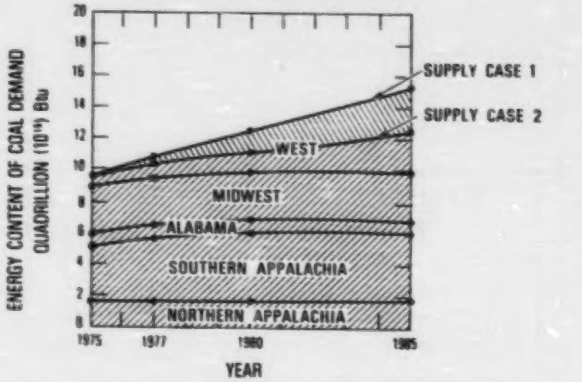
SUPPLY CASE 2:

- INDUSTRY PROJECTIONS WITH REDUCED GROWTH IN WESTERN COAL PRODUCTION:

  20% ANNUAL PRODUCTION GROWTH (1975–1980)
  10% ANNUAL PRODUCTION GROWTH (1980–1985)

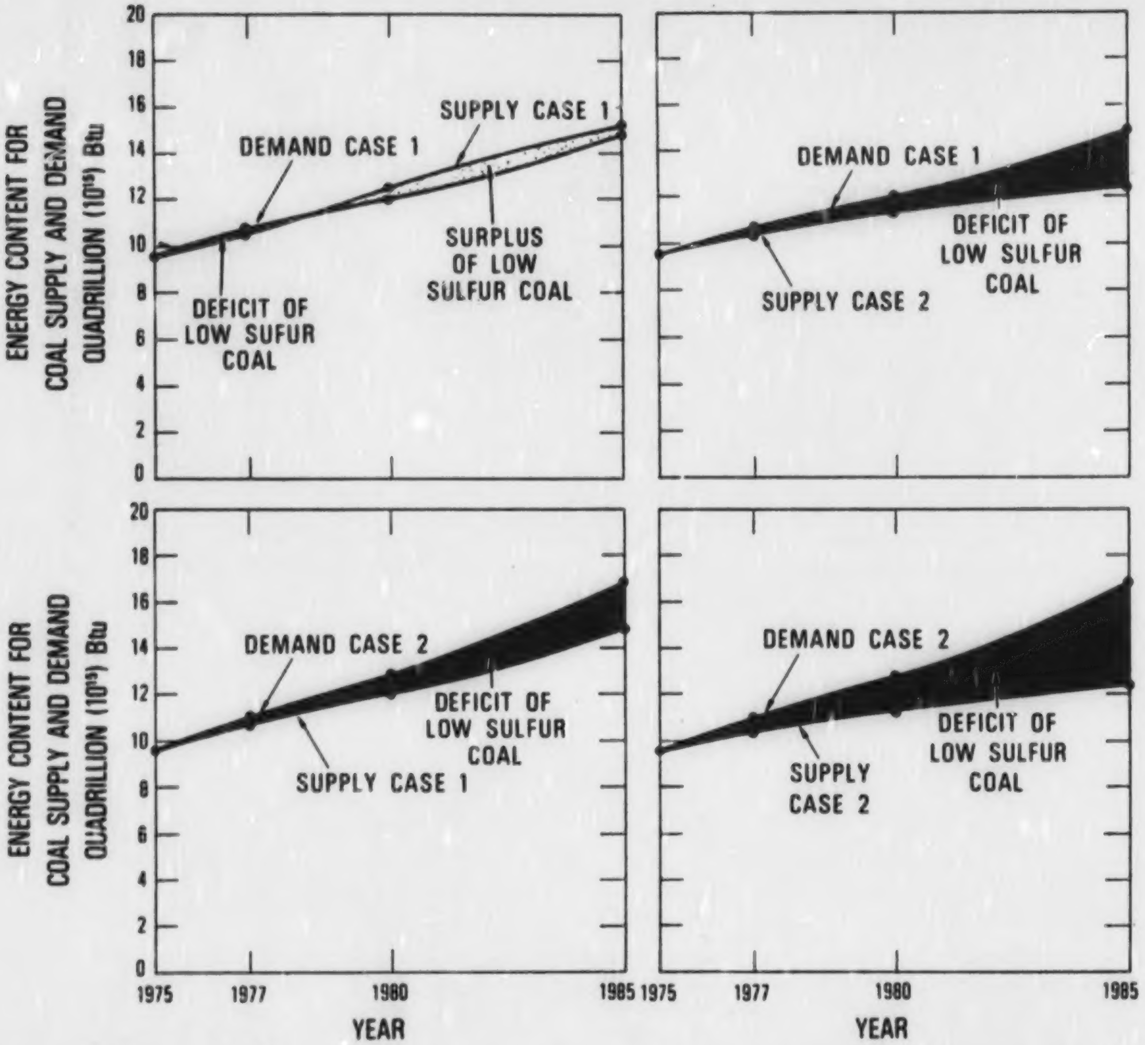
LOW SULFUR COAL SUPPLY CASES

Figure 1.1.6



U.S. LOW SULFUR COAL SUPPLY FORECAST: CASES 1 AND 2

Figure 1.1.7



COMPARISON OF SUPPLY AND DEMAND CASES FOR LOW SULFUR COAL

Figure 1.1.8

- IF WESTERN COAL PRODUCTION GROWS AT PROJECTED RATES, AND

IF 60% OF NEW COAL FIRED POWER PLANTS INSTALL SCRUBBERS,

THEN, NO SHORTAGE OF LOW SULFUR COAL TO MEET EPA EMISSIONS STANDARD IS EXPECTED DURING THE PERIOD 1975-1985

CONCLUSIONS FROM ANALYSIS OF SUPPLY AND DEMAND FOR LOW SULFUR COAL

Figure 1.1.9a

- HOWEVER, IF GROWTH RATES OF WESTERN COAL PRODUCTION ARE REDUCED BY ABOUT ONE-THIRD, AND

IF, AGAIN, 60% OF NEW COAL FIRED POWER PLANTS INSTALL SCRUBBERS,

THEN, AN ANNUAL SHORTAGE OF LOW SULFUR COAL OF
0.8×10^{15} Btu (40 MILLION TONS) IN 1980 AND
2.4×10^{15} Btu (120 MILLION TONS) IN 1985
could occur

CONCLUSIONS FROM ANALYSIS OF SUPPLY AND DEMAND FOR LOW SULFUR COAL

(Continued)

Figure 1.1.9b

- IF WESTERN COAL PRODUCTION GROWS AT PROJECTED RATES, AND
- IF ONLY 35% OF NEW COAL FIRED POWER PLANTS INSTALL SCRUBBERS,

AN ADDITIONAL ANNUAL SHORTAGE OF LOW SULFUR COAL OF
0.8×10^{15} Btu (40 MILLION TONS) IN 1980 AND
2.0×10^{15} Btu (100 MILLION TONS) IN 1985
COULD OCCUR

CONCLUSIONS FROM ANALYSIS OF SUPPLY AND DEMAND FOR LOW SULFUR COAL

(Continued)

Figure 1.1.9c

THUS, THERE IS A POTENTIAL SHORTAGE OF LOW SULFUR COAL BETWEEN THE PRESENT AND 1985 (and thereafter). CAN THE USE OF COAL CLEANING INCREASE SUPPLY OF LOW SULFUR COAL TO MEET THIS POTENTIAL DEFICIT?

THE ROLE OF COAL CLEANING
Figure 1.1.10

YEAR	MECHANICALLY CLEANED COAL	
	(PERCENT)	(MM TONS)
1965	64.9	332
1966	63.8	340
1967	63.2	350
1968	62.5	340
1969	58.7	324
1970	53.6	322
1971	49.1	271
1972	49.2	292
1973	49.1	298

QUANTITIES U.S. COAL MECHANICALLY CLEANED (1965-1973)
Figure 1.1.11

REGION	CLEANED (PERCENT)	PERCENT MEETING EPA SULFUR EMISSIONS STANDARDS	
		BEFORE CLEANING	AFTER CLEANING
NORTHERN APPALACHIA	73.3	4	12
SOUTHERN APPALACHIA	60.0	35	50
ALABAMA	95.0	30	30
EASTERN MIDWEST	81.0	1	2
WESTERN MIDWEST	51.1	2.5	5.5
WESTERN	15.8	70	94

U.S. COAL CLEANING BY REGION (1973)
Figure 1.1.12

- IF NEW COAL CLEANING CAPACITY IS EMPLOYED TO REDUCE SULFUR CONTENT OF ALL NEW SOURCES OF COAL SUPPLY TO THE EXTENT PRACTICABLE WITH STATE-OF-THE-ART COAL CLEANING TECHNOLOGY,

  THEN, THE POTENTIAL DEFICIT OF LOW SULFUR COAL IN 1985 IS REDUCED BY 0.5 × 10^{15} BTU (25 MILLION TONS) FOR SUPPLY CASE 2 AND BY 1.2 × 10^{15} BTU (60 MILLION TONS) FOR SUPPLY CASE 1

THE NEED FOR COAL CLEANING: CONCLUSIONS

Figure 1.1.13a

- IF THE GROWTH RATE IN PRODUCTION OF SOUTHERN APPALACHIAN COAL WERE INCREASED ABOVE 2% PER YEAR (SUPPLY CASES 1 AND 2), AND ADDITIONAL COAL CLEANING CAPACITY CONSTRUCTED FOR THE NEW COAL, THEN SUBSTANTIAL REDUCTIONS IN ANY DEFICIT OF LOW SULFUR COAL COULD BE ACHIEVED:

ANNUAL INCREASE IN SOUTHERN APPALACHIAN COAL PRODUCTION	ADDITIONAL LOW SULFUR COAL
6%	1.1 x 10^{15} BTU
8%	1.7 x 10^{15} BTU
10%	2.5 x 10^{15} BTU

THE NEED FOR COAL CLEANING: CONCLUSIONS

Figure 1.1.13b

	DEMAND CASE 1: 60% OF NEW COAL FIRED POWER PLANTS USE SCRUBBERS	DEMAND CASE 2: 35% OF NEW COAL FIRED POWER PLANTS USE SCRUBBERS
SUPPLY CASE 1: *HIGH WESTERN COAL GROWTH RATE (35% AND 20%)*	NO DEFICIT IN LOW SULFUR COAL IN 1985	2.0 × 10^{15} BTU (100 MILLION TONS) SHORTAGE OF LOW SULFUR COAL IN 1985
SUPPLY CASE 2: *REDUCED WESTERN COAL GROWTH RATE (15% AND 10%)*	2.4 × 10^{15} BTU (120 MILLION TONS) SHORTAGE OF LOW SULFUR COAL IN 1985	4.4 × 10^{15} BTU (220 MILLION TONS) SHORTAGE OF LOW SULFUR COAL IN 1985
SUPPLY CASE 2 with 10% GROWTH IN SOUTHERN APPALACHIAN COAL AND MAXIMAL USE OF COAL CLEANING	NO DEFICIT IN LOW SULFUR COAL IN 1985; 3% ANNUAL GROWTH IN COAL CLEANING CAPACITY	1.3 x 10^{15} Btu (65 MILLION TONS) SHORTAGE OF LOW SULFUR COAL IN 1985; 2% ANNUAL GROWTH IN COAL CLEANING CAPACITY

THE NEED FOR COAL CLEANING: CONCLUSIONS

Figure 1.1.13c

COAL RESOURCES, A CONTINUING ASSESSMENT

S. Z. Altschuler
J. E. Johnston

Abstract

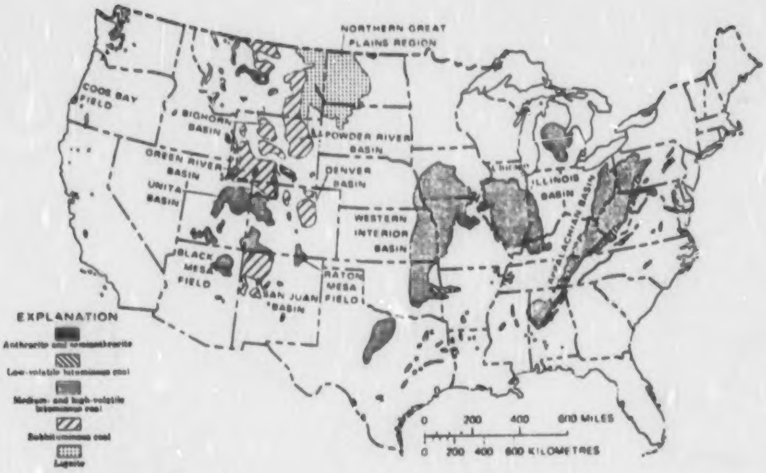
Coal resources of the United States, as estimated in January, 1974, total about 4 trillion short tons, of which 437 billion tons constitute the coal base (measured and indicated reserves).

Approximately 200 billion tons of coal in this reserve base is sufficiently low in sulfur content (<1 percent sulfur) to be used with little or no sulfur reduction treatment. Some coals are enriched with traces of various elements, notably beryllium and cadmium, which may, upon further concentration in ash or other products, become environmentally hazardous. Other minor or trace elements may be critical factors in process technology.

Unusual concentrations of zinc and uranium in coal and lignites of particular coal basins, notably in Texas and North Dakota, exemplify opportunities for recovery of those resources as well as the inherent properties of coal.

It is vital to augment conventional evaluation of coal quality with detailed and regional analyses of the inorganic constituents in coal. The U.S. Geological Survey is currently establishing, in cooperation with other federal and state agencies, a national inventory of coal data which will be placed in computerized data banks. The data will be recoverable not only in written form, but on various scale topographic maps in a great number of different combinations.

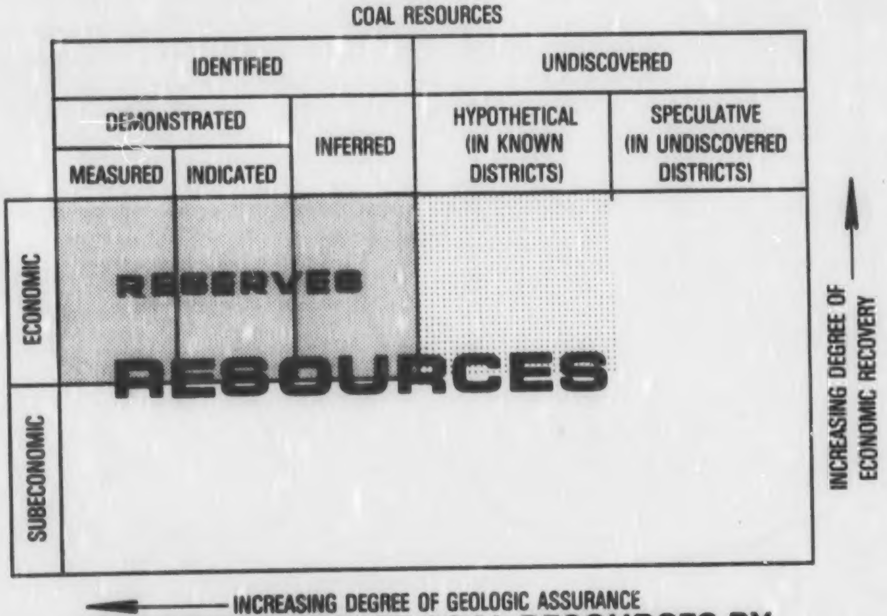
(Editor's note: This paper had not been approved for publication and therefore the abstract only is offered. Readers are directed to the panel discussion portion of this document for additional information from author Altschuler.)


NORTHERN GREAT PLAINS REGION
COOS BAY FIELD
BIGHORN BASIN
POWDER RIVER BASIN
GREEN RIVER BASIN
DENVER BASIN
UINTA BASIN
WESTERN INTERIOR BASIN
ILLINOIS BASIN
APPALACHIAN BASIN
BLACK MESA FIELD
SAN JUAN BASIN
RATON MESA FIELD
EXPLANATION
Anthracite and semianthracite
Low-volatile bituminous coal
Medium- and high-volatile bituminous coal
Subbituminous coal
Lignite
0 200 400 600 MILES
0 200 400 600 KILOMETRES

COAL FIELDS OF THE CONTERMINOUS UNITED STATES

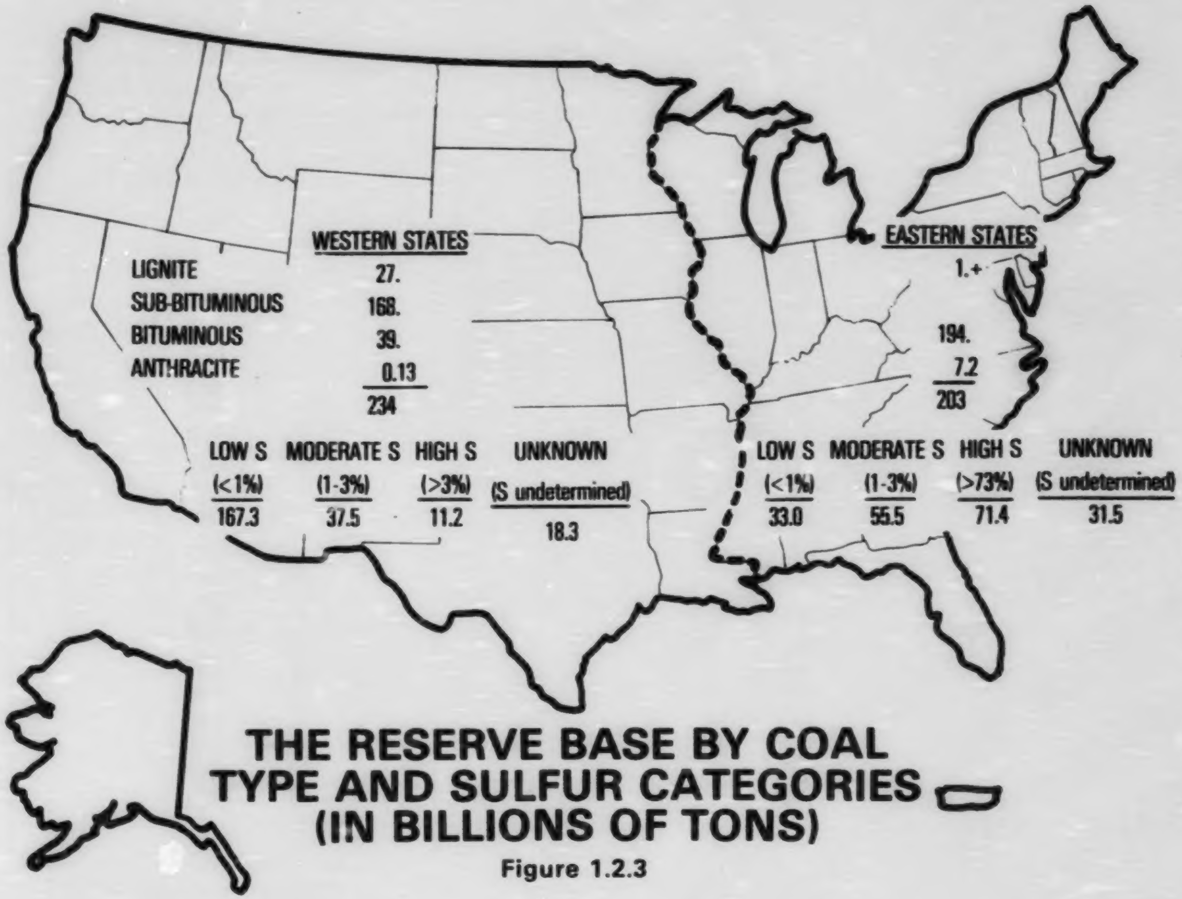
(FROM AVERITT, 1975)

Figure 1.2.1


COAL RESOURCES
IDENTIFIED
UNDISCOVERED
DEMONSTRATED
MEASURED
INDICATED
INFERRED
HYPOTHETICAL (IN KNOWN DISTRICTS)
SPECULATIVE (IN UNDISCOVERED DISTRICTS)
ECONOMIC
SUBECONOMIC
RESERVES
RESOURCES
INCREASING DEGREE OF ECONOMIC RECOVERY
INCREASING DEGREE OF GEOLOGIC ASSURANCE

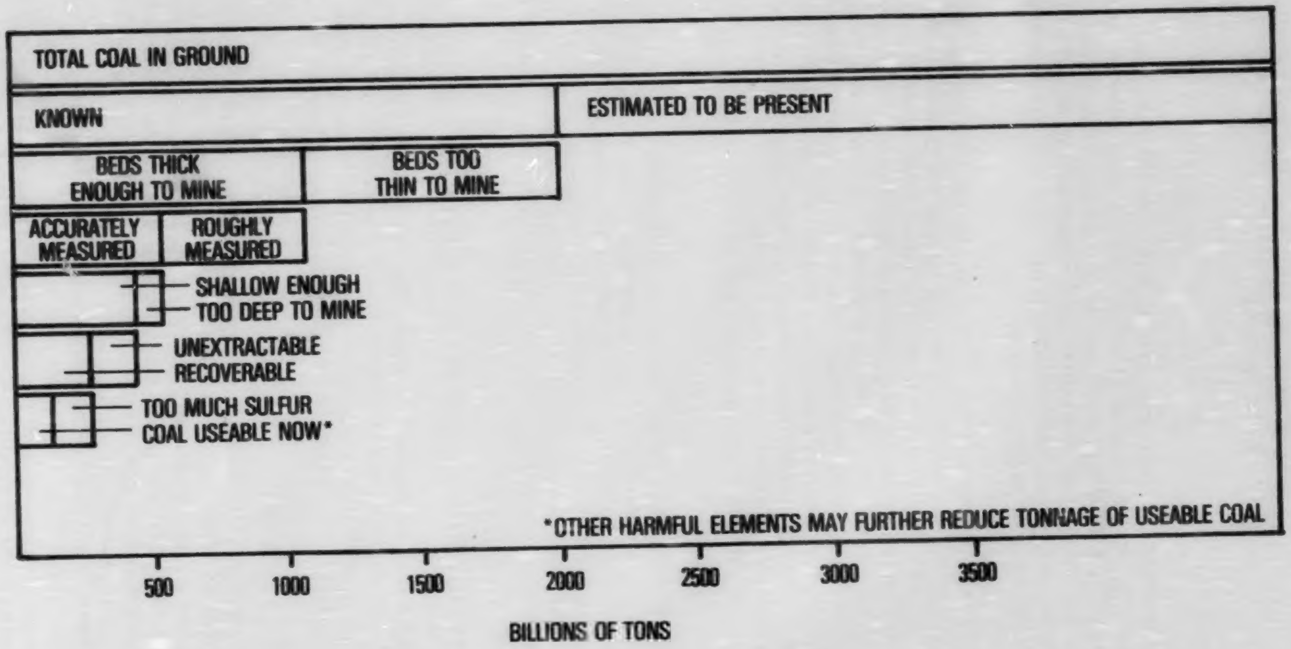
CLASSIFICATION OF COAL RESOURCES BY THE U. S. GEOLOGICAL SURVEY AND THE U. S. BUREAU OF MINES

Figure 1.2.2


WESTERN STATES
LIGNITE 27.
SUB-BITUMINOUS 168.
BITUMINOUS 39.
ANTHRACITE 0.13
234
LOW S (<1%) 167.3
MODERATE S (1-3%) 37.5
HIGH S (>3%) 11.2
UNKNOWN (S undetermined) 18.3
EASTERN STATES
1.+
194.
7.2
203
LOW S (<1%) 33.0
MODERATE S (1-3%) 55.5
HIGH S (>73%) 71.4
UNKNOWN (S undetermined) 31.5

THE RESERVE BASE BY COAL TYPE AND SULFUR CATEGORIES (IN BILLIONS OF TONS)

Figure 1.2.3



*OTHER HARMFUL ELEMENTS MAY FURTHER REDUCE TONNAGE OF USEABLE COAL

HOW MUCH OF THE U.S. COAL IS PRESENTLY EXTRACTABLE AND USABLE?

Figure 1.2.4

CONTAMINANTS IN COALS AND COAL RESIDUES

E. M. Wewerka
J. M. Williams
N. E. Vanderborgh

INTRODUCTION

Coal is one of our most abundant sources of energy. Even with the enhanced role that coal will play in the future, known reserves are estimated to be sufficient for at least three or four centuries. The utilization of this form of fossil fuel, however, is fraught with environmental problems. In each step from mine to utilization various contaminants are released into the environment. The dust and gases in mines, drainage from coal mines and refuse, and stack emissions from coal-fired systems are examples of environmental problems that continue to plague our society.

In the past, the environmental degradation from coal mining, processing, and burning was reluctantly accepted. However, concern over environmental quality has resulted in the establishment of regulations or guidelines for nearly all forms of coal utilization. Unfortunately, in many instances, the statutory regulation of coal pollution has preceded the availability of the technology necessary to achieve compliance with the law. Therefore, over the next decade, a massive effort must be launched to develop suitable environmental control technology. The technical approach to control of coal contamination, however, is not straight-forward. Compromises and trade-offs between efficient energy use and the sometimes uncertain environmental consequences must be considered. Often the choice of control technology for one area will affect that required in another. Ultimately, decisions must be based on knowledge of the origins, magnitude, and behavior of the various kinds of coal contaminants.

In this paper, we review some of the current information on the chemical and physical structure of coals to establish the source and nature of potential environmental contaminants. With this as background, we then discuss the nature of the major contaminants released into the environment during coal mining, handling, and combustion. Finally we will consider coal preparation, which is one of the most widely used forms of environmental control technology. Our discussion of coal cleaning will center on the environmental compromises and implications attendant in using this method to produce a cleaner burning fuel.

THE ORIGIN OF ENVIRONMENTAL CONTAMINANTS IN THE STRUCTURE OF COAL

Coal is a combustible carbonaceous rock formed from plant remains and various inoganic components (Figure 1.3.1). Because of this, coal is a highly heterogeneous materal that contains a wide variety of inorganic and organic impurities in addition to the carbonaceous matrix. Most of the environmental contamination from coals is a direct consequence of these impurities.

The Formation and Structure of Coal

The diverse composition of coal arises from the geological and chemical conditions present during coal formation. As outlined in Figure 1.3.2., the first step of coal formation is thought to be the deposition of plant remains and inorganic sediments under reductive conditions, usually in a freshwater swamp or lake. Eventually, under heat and pressure, these deposits are transformed into peat. The step from peat to coal is a chemical modification that involves mainly the loss of CO_2 and water.

Physically, coal contains both organic-rich and inorganic-rich regions. The organic part of the coal structure, which comprises about 70 to 90 percent of the total, is present in the form of distinct physical entities called macerals, which have differing sizes and shapes (Figure 1.3.3). The morphologies of the macerals are thought to be related to the original plant constituents. The mineral matter in coals appears as small particles and grains or thick layers interspersed within the organic components.

Environmental Contaminants From the Organic Structure of Coal

The organic coal components contain mainly, C, H, N, O, and S; however, as detailed in Figure 1.3.4, there is considerable variation in these elements in coals. Lower rank coals, such as lignite, are typified by a lower percentage of C and H and a relatively higher percentage of N, O, and S, whereas the converse is true for the higher rank coals.

The organic matter in coals is predominately in the form of aromatic and hydroaromatic hydrocarbons. The O, S, and N atoms form various functional groups that are dispersed throughout the carbon skeleton. The prevalent functional groups in coals are phenols, acids, ethers, and groups containing sulfur and nitrogen.

Various models have been proposed to illustrate the structural details of the organic coal components. These are based on the known chemistry of coals, and are meant to suggest the major features of molecular composition rather than to be exact representations. One of the more popular structural models, devised by Wiser, is shown in Figure 1.3.5. This structure, of course, bears a remarkable resemblance to the molecular configurations present in the humic components of plant materials.

The molecule pictured in Figure 1.3.5 is very large, and, indeed, the general chemical inertness of coals is a reflection of the large sizes of their constituent molecules. However, during combustion, the large organic molecules can break down into smaller entities which can more easily escape into the environment as gaseous pollutants or as water contaminants. Also, coals contain some smaller organic molecules that are entrapped within the coal lattice. These may be released during processing or storage without the necessity of molecular cleavage.

By referring to the model in Figure 1.3.5, it is relatively easy to envision the types of organic molecules that are released by coals during combustion, oxidation, or weathering. Due to their preponderance, various aromatic and aliphatic hydrocarbons are common contaminants. Also, because heteroatom linkages are often susceptible to cleavage, molecules containing N, O, and S atoms are prevalent coal contaminants. Typical examples of the types of organic molecules in the emissions or discharges from coals are pictured in Figures 1.3.6a, b and c.

Environmental Pollutants From the Inorganic Constituents of Coal

Most of the inorganic coal components were deposited either as sediments in the original bed or as secondary materials during the formation of the coal; however, some of the trace or minor elements in coals were probably present originally in the plants.

The most abundant inorganic elements in coals (excluding S, N, and O) are listed in Figure 1.3.7. These are the elements that, for the most part, form the major minerals found in coals. These minerals fall into the four main classes listed in Figure 1.3.8. They are the aluminosilicates (Na, K, Al, Si), the sulfides (Fe), the carbonates (Ca, Mg, Fe), and silica (Si). Generally, the aluminosilicates (clay minerals) and quartz tend to be chemically stable. Neither is volatile or likely to be leached from the coal. During combustion these minerals will form ash. Another troublesome aspect of the clay minerals is that they will fragment during burning to form small particulates (fly ash) that mix with the stack gases. The carbonates also form ash during combustion. In addition, they are partially water soluble and may be leached out of coals or wastes.

Among all of the coal constituents, environmental contamination caused by pyritic materials is the most severe. The sulfides are not particularly soluble or volatile *per se*, but when pyrite (or marcasite) is exposed to atmospheric conditions, it can interact with air and water at ambient temperature to produce soluble iron sulfate and sulfuric acid. This reaction of the iron sulfides in coals is, in fact, responsible for the formation of acid mine drainage, a most serious water pollution problem. Also, during the combustion of coal, the sulfur in the iron sulfides (along with added amounts of organic sulfur) is oxidized to SO_2, the most prevalent air contaminant associated with the burning of coal. The chemical reactions for the formation of sulfuric acid and sulfur dioxides from iron sulfides appear in Figure 1.3.9.

In addition to these major inorganic elements, coals also contain a wide variety of trace or minor elements. A listing of some of the trace elements of environmental concern in coals is given in Figures 1.3.10a and b. The soluble forms of these elements may be released into the environment by aqueous leaching of coals or their residues. Also, some of the toxic trace elements assume volatile forms during coal burning; these can escape into the atmosphere along with the more inert gaseous products.

THE RELEASE OF ENVIRONMENTAL CONTAMINANTS FROM COALS DURING PROCESSING AND COMBUSTION

In the preceding section, we discussed the structure of coal, and how the various types of contaminants originate in the coal. In addition, we briefly considered how these contaminants are transported into the environment, either as gaseous or water-borne pollutants (Figures 1.3.11a and b). In this section, we will consider the types of contaminants that are released from coals during the various processing and utilization steps. Then, we will go on to discuss the environmental circumstances surrounding coal preparation, particularly to emphasize its use as an environmental control method.

The usual sequence of coal production and utilization steps appears in Figure 1.3.12a. After mining, nearly all coal is subjected to storage and transportation steps prior to utilization (combustion). In addition, about one-half of the coal mined in the U.S. is washed or prepared before it is used to remove some of the unwanted mineral matter. Each processing, handling, or utilization step results in the production of significant environmental pollutants.

Environmental Pollution from Coal Mining

Coal mining is one of our most dangerous industries. Therefore, the environmental and health hazards associated with this phase of coal production are under much scrutiny. As shown in Figure 1.3.12b, both atmospheric and aqueous contaminants are produced by coal mining.

The main atmospheric contaminants from coal mining are dust and gases. Dust is generated by physical abrasion of the coal, and under confined conditions, such as in underground mines, the respiration of this dust is a major health problem. The release of methane and other combustible gases from the coal beds is another serious problem associated with coal mining. Underground, when ventilation is poor, these gases can accumulate in explosive concentrations.

Acid drainage is by far the most serious water problem associated with coal mining. As detailed earlier, acid formation results from the pyritic material present in the coal. More than 3 million tons of sulfuric acid are discharged annually into waterways from coal mines. Acid mine drainage is responsible for contaminating some 7,000 miles of streams in the Appalachian region.

The spoil material from coal mining (overburden and mine wastes) contributes to contamination on a much smaller scale than do mines. For environmental purposes most of this type of waste is used as fill material after mining has been completed. However, coal mine spoils are a local source of acid drainage and mineral contaminants in water.

Contaminants Produced by Coal Storage and Transportation

Neither the seriousness nor the extent of environmental contamination from coal storage or transportation has been adequately assessed. As seen in Figure 1.3.12c, the potential exists for the release of pollutants into both the atmosphere and aqueous environment during these handling operations. Because of the transient nature of coal during storage and transportation, gaseous and aqueous pollutants from these sources will often be more diffuse or less visible than those from stationary sources.

Environmental Contamination From Coal Combusion

The environmental contaminants produced by the burning of coal in boilers, power generators, and other stationary sources (see Figure 1.3.12d) are well identified, and we need dwell only briefly on this topic here.

The oxides of sulfur, nitrogen, and carbon are the most notorious air contaminants produced by the combustion of coal. These contaminants enter the atmosphere in great quantities. In 1974, about 20 million tons of SO_2 and 5 million tons of nitrogen oxides (NO_x) were discharged into the environment from coal burning. In addition to these gaseous contaminants, coal combustion also produces large quantities of finely divided mineral particulates (fly ash) that also escape into the environment in copious quantities. Finally, in the last few years it has been recognized that certain toxic trace elements, such as Pb, Hg, As, and Cd may be released into the atmosphere in worrisome quantities from coal combustion sources. It is not yet clear whether these elements are in a completely volatile state or whether they are absorbed at the surface of fly ash or other particulate emissions.

The burning of coal also produces solid waste materials that need to be disposed of in environmentally compatible ways. The bulk of this residue is bottom ash formed by the nonvolatile mineral matter in the coal. In addition, to lessen the air pollution load, increasing amounts of fly ash are being removed from the stack components by precipitators and other devices. About 70 million tons of bottom and fly ash are produced annually in the U.S. from coal combustion. There is growing awareness that the discarded solid wastes from coal combustion may themselves be a serious source of environmental contamination. In particular, these materials may be subjected to leaching by rainwater or surface flows that could produce mineral or trace element contamination.

Environmental Contaminants From Coal Preparation

The final coal processing step that we will consider is coal washing or preparation. In contrast to the previous areas discussed, this step is conducted specifically to reduce the concentration of some of the undesirable mineral impurities. There are, of course, economic benefits to be derived from coal washing, such as the reduced cost of shipping, storing and burning a higher quality product, but for the future, coal preparation is best envisioned as a pollution control measure.

Coal preparation is largely a mechanical process, involving a series of crushing, sizing, separating, and drying steps. In most cases, the coal is separated from the mineral matter on the basis of density. Modern coal preparation plants can recover about 90 percent of the energy content of the coal, while reducing the sulfur content to less than 1 percent.

The mineral refuse and wastes from coal preparation are also a recognized source of environmental contamination, as detailed in Figures 1.3.12e and 1.3.13. Coal preparation refuse is subjected to weathering and leaching processes that frequently produce acids and highly mineralized drainage. The relative seriousness of this problem can be judged by comparing the quality of the aqueous effluents from typical coal refuse dumps (Figure 1.3.14) with the proposed EPA standards for such effluents shown in Figure 1.3.15. It is seen that in no instance does the quality of the waste bank effluents (e.g., see the Fe, Al, Mn, and pH values) approach the criteria established by EPA. It has been estimated that more than 3,000 miles of streams in Appalachia alone are contaminated from coal refuse dumps.

In addition to water contamination, burning refuse dumps produce substantial air pollution. Approximately 1 percent of the total nationwide quantities of sulfur-, nitrogen-, and carbon-oxide emissions are attributed to burning coal wastes. Although this may be considered a small contribution, these contaminants occur in highly localized regions. Finally, we must also point out that structural instabilities in coal refuse banks have resulted in landslides or cave-ins that have claimed several hundred lives over the last 20 years. The problems associated with coal refuse dumps are not isolated incidences. Of the 3,000 to 5,000 refuse dumps in the U.S., about one-half are the sources of some type of health or environmental problem.

Environmental Trade-offs in the Coal Preparation/Utilization Cycle

A preliminary function of coal preparation is to reduce the mineral matter in raw coals so that the emissions from the burning of these coals can meet established guidelines. Indeed, about 100 million tons of potential contaminants are removed annually from U.S. coals by coal preparation. The waste materials produced by coal preparation are a major source of environmental contamination.

As shown in Figures 1.3.16 and 1.3.12f, coal preparation is in effect an environmental trade-off: a serious health and pollution problem is simply being transferred from one segment of the environment to another. Undoubtedly the rationale for this transfer is based on the assumption that contamination from solid waste material concentrated in remote disposal areas is easier to control or alleviate than the more ubiquitous forms that are discharged by the burning of coal. Conceivably, the combined hazards from coal refuse dumps present a less serious threat to human health than the highly mobile emissions from burning coal, although this point could be debated at some length. Environmental control of discarded coal refuse, until recently, has been largely neglected. Until adequate assessment and cleanup of this source of contamination is effected, the full implications of coal preparation as a viable pollution control measure cannot completely be evaluated.

SUMMARY

Most of the major environmental pollutants from coals originate as impurities in the coal structure. These include various organic compounds, minerals, and trace elements that are released into the air and water when coal is mined, processed, and utilized. The use of coal preparation to produce cleaner burning fuels involves an environmental compromise, wherein reduced emissions and solid wastes from coal burning sources are achieved at the expense of greater environmental degradation from coal cleaning wastes.

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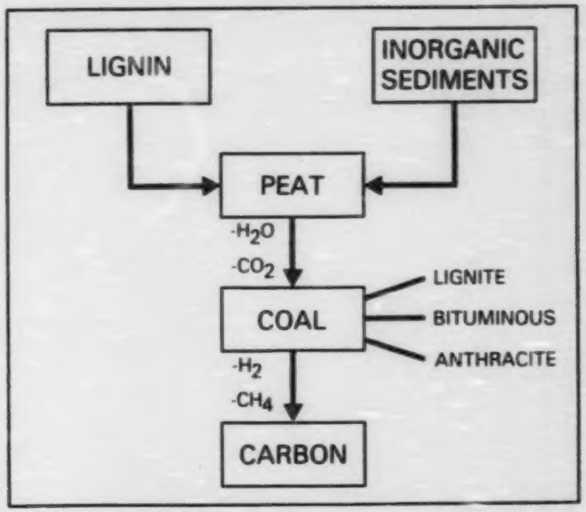
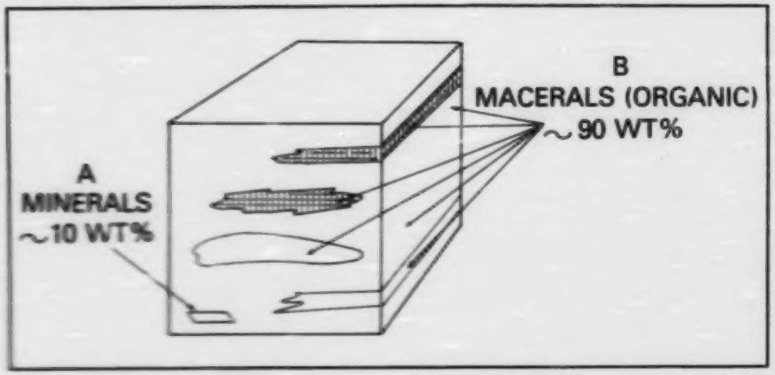
COAL IS A COMBUSTIBLE SEDIMENTARY ROCK FORMED FROM PLANT MATERIALS AND INORGANIC SEDIMENTS IN VARIOUS STAGES OF METAMORPHISM

WHAT IS COAL?
Figure 1.3.1


LIGNIN
INORGANIC SEDIMENTS
PEAT
$-H_2O$
$-CO_2$
COAL
LIGNITE
BITUMINOUS
ANTHRACITE
$-H_2$
$-CH_4$
CARBON

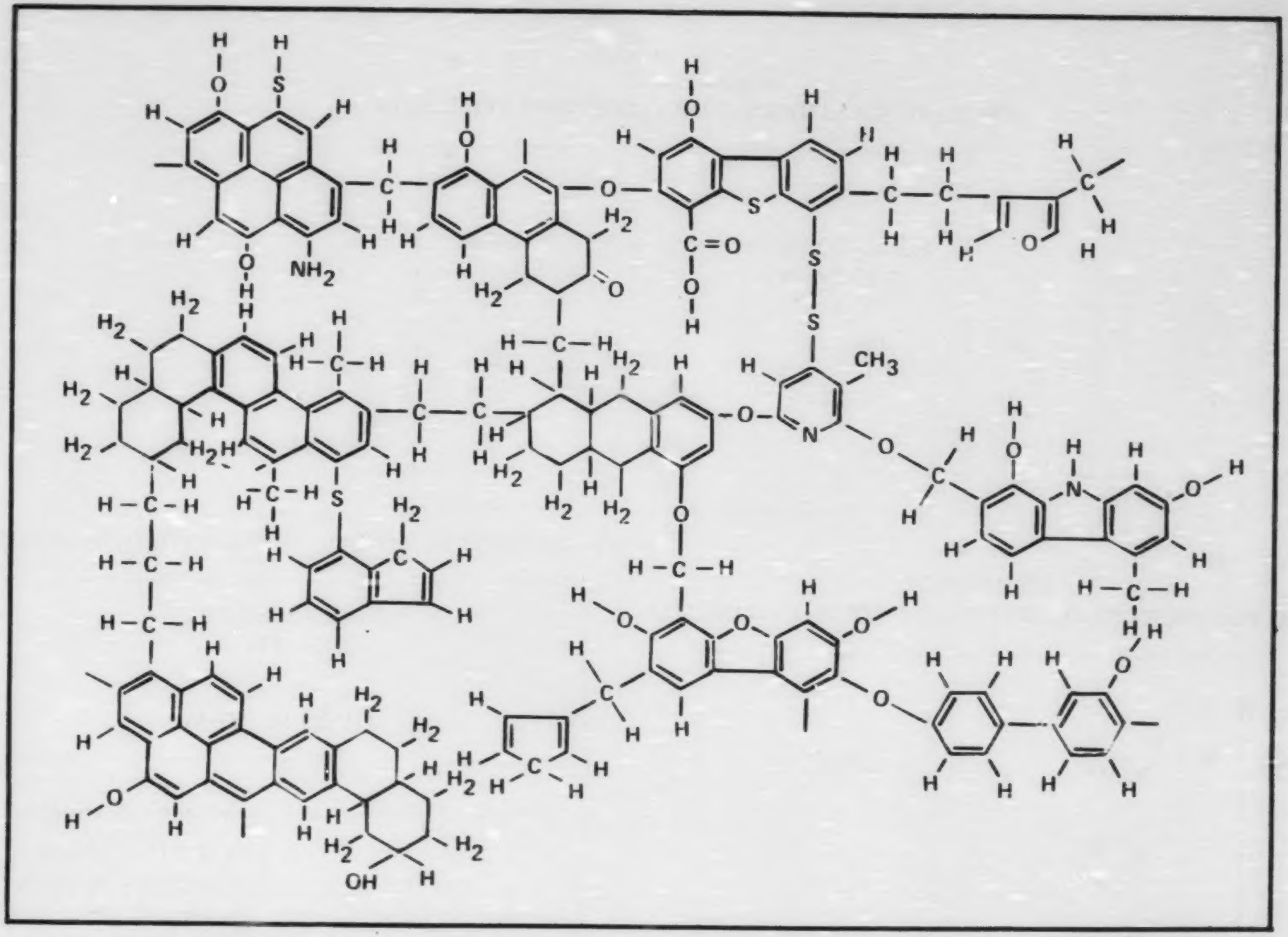
COAL-FORMING PROCESSES
Figure 1.3.2


A
MINERALS
~10 WT%
B
MACERALS (ORGANIC)
~90 WT%

PHYSICAL COMPOSITION OF COAL (SPACKMAN)
Figure 1.3.3

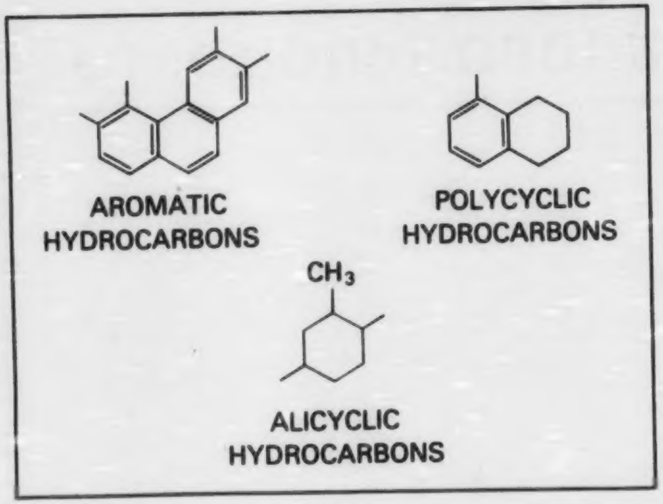
ELEMENT	RANGE (WT%)
CARBON	65 - 93
HYDROGEN	2.0 - 6.0
OXYGEN	2.0 - 20
SULFUR	0.5 - 6.0
NITROGEN	0.5 - 2.0

ELEMENTAL COMPOSITION OF ORGANIC COAL COMPONENTS
Figure 1.3.4



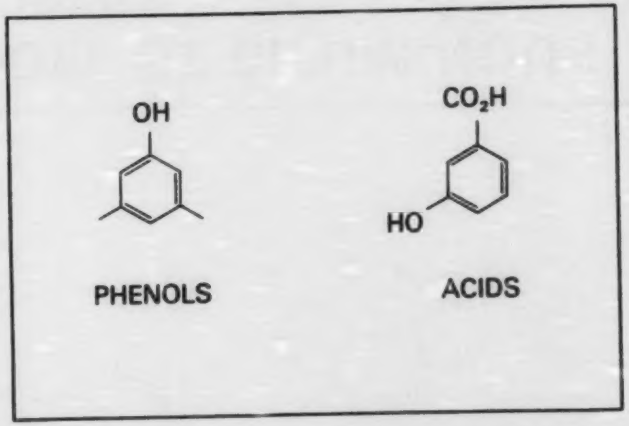
FUNCTIONAL GROUP MODEL OF BITUMINOUS COAL (WISER)

Figure 1.3.5


AROMATIC
HYDROCARBONS
POLYCYCLIC
HYDROCARBONS
CH₃
ALICYCLIC
HYDROCARBONS

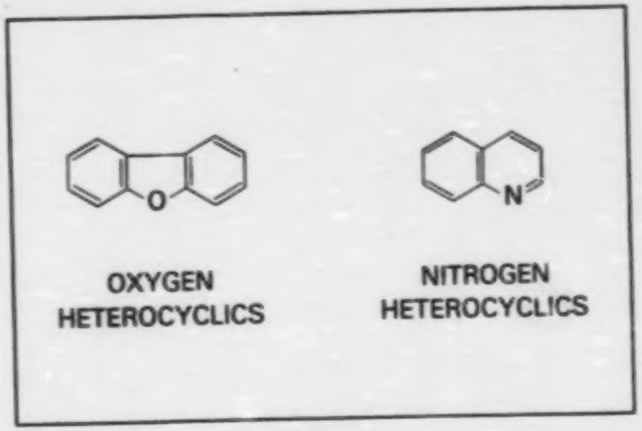
POTENTIAL ORGANIC CONTAMINANTS FROM COALS

Figure 1.3.6a


OH
PHENOLS
CO₂H
HO
ACIDS

POTENTIAL ORGANIC CONTAMINANTS FROM COALS
(CONTINUED)

Figure 1.3.6b


O
OXYGEN
HETEROCYCLICS
N
NITROGEN
HETEROCYCLICS

POTENTIAL ORGANIC CONTAMINANTS FROM COALS
(CONTINUED)

Figure 1.3.6c

ELEMENT	RANGE (WT%)
SILICON	0.6 - 6.1
IRON	0.3 - 4.3
ALUMINUM	0.4 - 3.1
CALCIUM	0.1 - 2.7
POTASSIUM	0.1 - 0.4
MAGNESIUM	0.1 - 0.3
TITANIUM	0.0 - 0.3
SODIUM	0 - 0.2

MAJOR INORGANIC ELEMENTS IN COALS

Figure 1.3.7

ALUMINOSILICATES (10-90 WT%)	SULFIDES (0-40%)
ILLITE KAOLINITE MIXED LAYER CLAYS	PYRITE MARCASITE

SILICA (0-20 WT%)	CARBONATES (0-10 WT%)
QUARTZ	CALCITE DOLOMITE SIDERITE

MAJOR MINERALS IN COALS

Figure 1.3.8

SULFUR OXIDE EMISSIONS
$4\,\underline{FeS_2} + 11\,O_2 \rightarrow 2\,Fe_2O_3 + 8\,\underline{SO_2} + \triangle$

ACID MINE DRAINAGE
$2\,\underline{FeS_2} + 2\,H_2O + 7\,O_2 \rightarrow 2\,FeSO_4 + 2\,\underline{H_2SO_4} + \triangle$

$\triangle$ = HEAT

IRON SULFIDES CAUSE MAJOR ENVIRONMENTAL PROBLEMS

Figure 1.3.9

ELEMENT*	RANGE (ppm)
BERYLLIUM	0 - 31
MANGANESE	6 - 181
NICKEL	0.4 - 104
COPPER	2 - 185
ZINC	0 - 6000
ARSENIC	0.5 - 106

*IN ORDER OF INCREASING ATOMIC WEIGHT

TRACE ELEMENTS OF ENVIRONMENTAL CONCERN IN COAL

Figure 1.3.10a

ELEMENT*	RANGE (ppm)
SELENIUM	0.4 - 8
YTTRIUM	0.1 - 59
CADMIUM	0.1 - 65
MERCURY	.01- 1.6
LEAD	4 - 218

*IN ORDER OF INCREASING ATOMIC WEIGHT

TRACE ELEMENTS OF ENVIRONMENTAL CONCERN IN COAL

(Continued)

Figure 1.3.10b

AQUATIC TRANSPORT MODE
● SOLUBLE ORGANIC MOLECULES
● POLYAROMATIC HYDROCARBONS
● LEACHABLE MINERALS AND TRACE ELEMENTS
● ACID DRAINAGE

SUMMARY OF POTENTIAL ENVIRONMENTAL CONTAMINANTS IN COALS

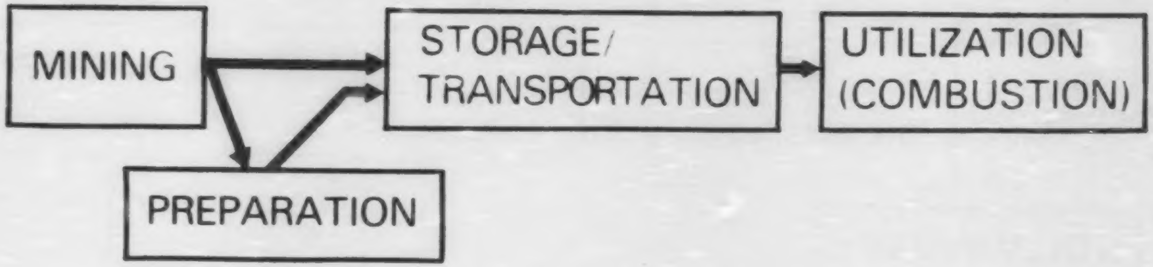
Figure 1.3.11a

ATMOSPHERIC TRANSPORT MODE
● VOLATILE HYDROCARBONS
● PARTICULATES AND DUST
● VOLATILE TRACE ELEMENTS
● OXIDES OF SULFUR, NITROGEN AND CARBON

SUMMARY OF POTENTIAL ENVIRONMENTAL CONTAMINANTS IN COALS

(Continued)

Figure 1.3.11b


MINING
STORAGE/
TRANSPORTATION
UTILIZATION
(COMBUSTION)
PREPARATION

COAL PROCESSING STEPS

Figure 1.3.12a

MINING

ATMOSPHERIC POLLUTION	AQUATIC/ TERRESTRIAL POLLUTION
● HYDROCARBON GASES ● DUST	● SPOIL LEACHING/ BURNING ● ACID DRAINAGE

ENVIRONMENTAL CONTAMINATION FROM COAL MINING

Figure 1.3.12b

STORAGE AND TRANSPORT

ATMOSPHERIC POLLUTION	AQUATIC/ TERRESTRIAL POLLUTION
● HYDROCARBON GASES ● DUST	● COAL LEACHING/ BURNING

ENVIRONMENTAL CONTAMINATION FROM COAL STORAGE AND TRANSPORT

Figure 1.3.12c

UTILIZATION (COMBUSTION)

ATMOSPHERIC POLLUTION	AQUATIC/ TERRESTRIAL POLLUTION
● SULFUR, NITROGEN AND CARBON OXIDES ● PARTICULATES ● TRACE ELEMENTS	● SLAG/FLY ASH LEACHING

ENVIRONMENTAL CONTAMINATION FROM COAL COMBUSTION

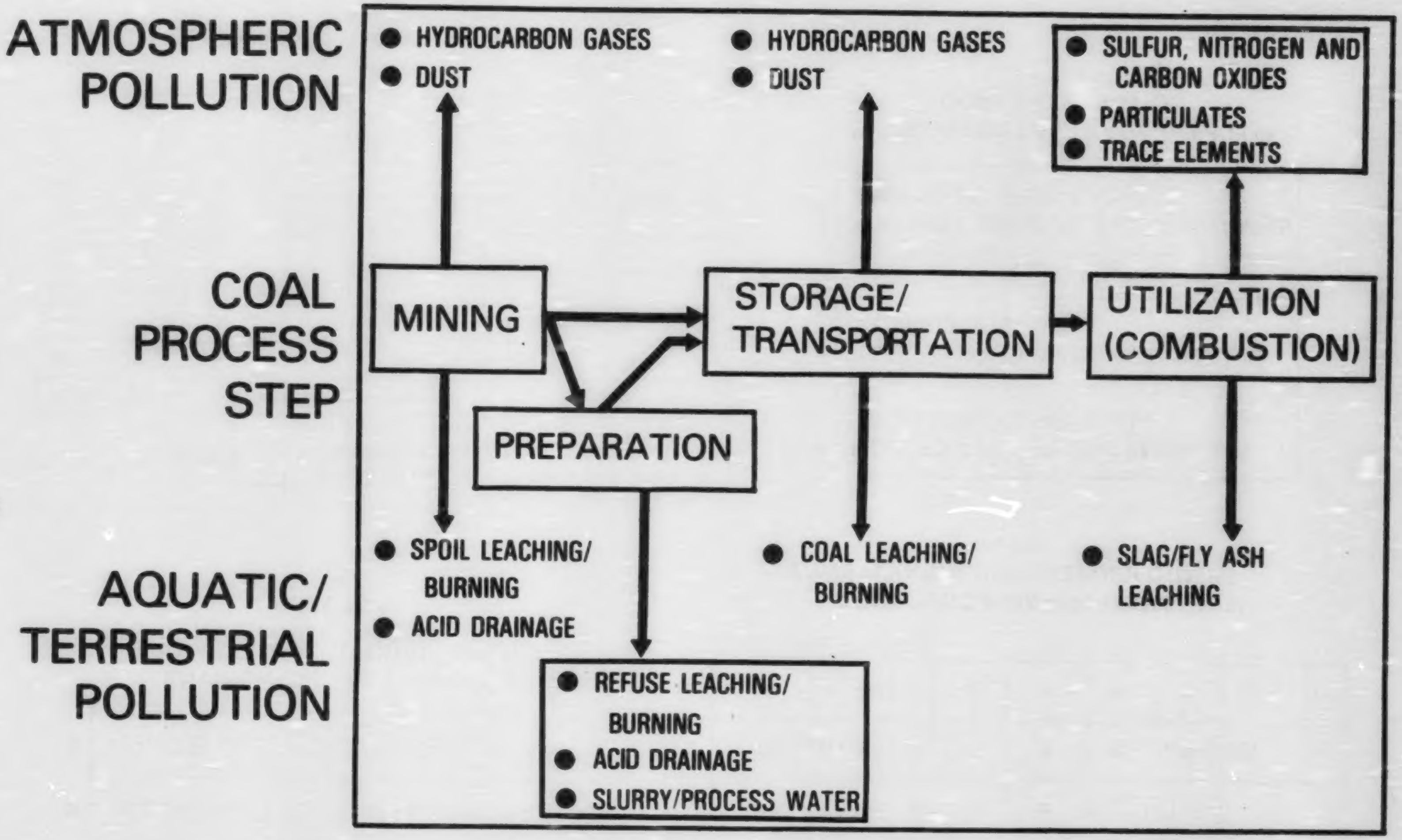
Figure 1.3.12d

PREPARATION

ATMOSPHERIC POLLUTION	AQUATIC TERRESTRIAL POLLUTION
NIL	● REFUSE LEACHING/ BURNING ● ACID DRAINAGE ● SLURRY/PROCESS WATER

ENVIRONMENTAL CONTAMINATION FROM COAL PREPARATION

Figure 1.3.12e


ATMOSPHERIC POLLUTION
COAL PROCESS STEP
AQUATIC/ TERRESTRIAL POLLUTION
● HYDROCARBON GASES
● DUST
● HYDROCARBON GASES
● DUST
● SULFUR, NITROGEN AND CARBON OXIDES
● PARTICULATES
● TRACE ELEMENTS
MINING
PREPARATION
STORAGE/ TRANSPORTATION
UTILIZATION (COMBUSTION)
● SPOIL LEACHING/ BURNING
● ACID DRAINAGE
● COAL LEACHING/ BURNING
● SLAG/FLY ASH LEACHING
● REFUSE LEACHING/ BURNING
● ACID DRAINAGE
● SLURRY/PROCESS WATER

BALANCE OF ENVIRONMENTAL CONTAMINATION FOR COAL PROCESSING AND UTILIZATION

Figure 1.3.12f

- STRUCTURAL INSTABILITIES
- ACIDIC AND MINERALIZED DRAINAGE
- WASTE DUMP BURNING

ENVIRONMENTAL PROBLEMS FROM DISCARDED COAL WASTES

Figure 1.3.13

SAMPLE	CONDUCTANCE (MICROMHOS-CM⁻¹)	pH	SULFATE	IRON	ALUMINUM	MANGANESE	CALCIUM	MAGNESIUM	SODIUM	POTASSIUM
1	13600	3.1	[illegible]	6168	998	63				
2	12400	2.7	17750	3197	1014	31				
3	4400	3.0	3000	30	87	50				
4	3500	3.7	1125	130	68	15	340	250	100	5
5	3000	4.0	1600	1	50	90	180	140	80	15

CONCENTRATIONS IN MILLIGRAMS PER LITER

AQUEOUS DRAINAGE FROM PENNSYLVANIA COAL REFUSE DUMPS

Figure 1.3.14

EFFLUENT CHARACTERISTIC	MAXIMUM FOR ANY 1 DAY (MILLIGRAMS PER LITER)	AVERAGE OF DAILY VALUES FOR 30 CONSECUTIVE DAYS SHALL NOT EXCEED (MILLIGRAMS PER LITER)
IRON, TOTAL	7.0	3.5
IRON, DISSOLVED	0.60	0.30
ALUMINUM, TOTAL	4.0	2.0
MANGANESE, TOTAL	4.0	2.0
NICKEL, TOTAL	0.40	0.20
ZINC, TOTAL	0.40	0.20
TSS	70	35
pH	WITHIN THE RANGE 6.0 TO 9.0	

EPA PROPOSED REGULATIONS FOR AQUEOUS EFFLUENTS FROM COAL MINING POINT SOURCES - OCTOBER 1975

Figure 1.3.15

- REDUCED ATMOSPHERIC EMISSIONS FROM COAL COMBUSTION
- REDUCED SOLID WASTES FROM COAL COMBUSTION

VERSUS

- INCREASED SOLID AND LIQUID WASTES FROM COAL PREPARATION

ENVIRONMENTAL TRADE-OFFS FOR COAL PREPARATION

Figure 1.3.16

EFFECT OF COAL PREPARATION ON NORTHERN APPALACHIAN RESERVES

R. E. Hucko
J. A. Cavallaro

The Air Quality Act of 1963 initiated a concerted effort by Federal and local governments to preserve the Nation's air quality. Because air pollution from combustion of fossil fuels has long been recognized as a problem by the EPA and its counterparts, major emphasis has been placed on developing methods for controlling sulfur oxide emissions.

Coal-fired electric utility plants are the major source of sulfur oxide air pollution in the United States today. In 1974, the electric utilities burned 390 million tons of coal with an average sulfur content of 2.2 percent. The amount of coal consumed by electric utilities is anticipated to reach 500 million tons by 1980 and approximately a billion tons by the year 2000. It is, therefore, imperative that sulfur oxide emissions be controlled.

Most of the Nation's coal reserves are too high in sulfur content to be fired directly and meet existing emission control standards without some pretreatment and/or stack gas scrubbing. It is recognized, however, that coal preparation will reduce the sulfur levels of the vast majority of reserves, thereby producing coal of adequately low sulfur content to meet existing standards or producing a partially desulfurized coal to be used in conjunction with stack gas scrubbing.

The Bureau of Mines has published reports detailing the extent of coal reserves of the United States by state, county, coalbed, rank, and sulfur content. In addition, other Bureau of Mines studies have delineated the sulfur release potential of coals from principal utility-coal-producing coalbeds of the United States. An effort to determine how the present reserves of the Northern Appalachian region would be distributed by sulfur content if they were subjected to various levels of coal preparation is reported in this paper. This study was applied to the bituminous coal reserves of the Northern Appalachian region because many of the coals of this area are amenable to upgrading by physical beneficiation. Included in this region are Maryland, Pennsylvania, Ohio, and 40 northern counties of West Virginia.

COAL WASHABILITY STUDIES

In 1965, the National Air Pollution Control Administration funded a study by the Bureau of Mines to determine the forms of sulfur in the major sources of utility steam coals and the washabilities of these coals. A washability analysis is an evaluation of those physical properties of a coal that determine its amenability to improvements in quality by cleaning. This includes stage crushing to release impurities and specific gravity fractionation to show the quality and quantity of the cleaned product. A washability study is made by testing the coal sample at preselected, carefully controlled specific gravities. This is termed "float-sink" analysis or specific gravity separation. Chemical analyses of the various specific gravity fractions of the coal are made, and these indicate how well the coal can be prepared. The results of this study have been published as a Bureau of Mines Report of Investigations (1) entitled "Sulfur Reduction Potential of the Coals of the United States."

Six-hundred-pound face samples were collected from surface and deep mines which were producing coal primarily for consumption by electric utilities. In general, coalbed samples were collected to reflect current production and known reserves. An attempt was made, however, to sample the largest utility-coal-producing mines; those sampled to date represent mines that provide more than 70 percent of the annual utility coal production.

The 600-pound channel samples collected in the field were processed in the following manner. Each sample was air-dried and then crushed to 1½-inch top size using a single-roll crusher. The sample was then coned, long-piled, and shoveled into four pans, according to ASTM specifications, and divided into two portions by combining opposite pans.

One of the 1½-inch by 0 portions was processed as is, and the other portion was crushed in a jaw mill to ⅜-inch top size. This ⅜-inch by 0 material was then riffled into two portions; one was processed as is (⅜-inch by 0), and the other was crushed to 14-mesh top size (14-mesh by 0) in a hammer mill and processed.

The various sized fractions were then float-sink tested at 1.30, 1.40, 1.60, and 1.90 specific gravities using a commercial organic liquid of standardized specific gravity; the solution tolerance is ±0.001 specific gravity unit and was monitored using a spindle hydrometer. Upon completion of the float-sink testing, the specific gravity fractions of the three sized samples were analyzed for ash, pyritic sulfur, and total sulfur content.

The float-sink data from the channel samples are not to be construed as representing the quality of the product loaded at the mine where the sample was taken but rather as indicating the quality of the bed in that particular geographical location. Float-sink data are based upon theoretically perfect specific gravity separations that are approached but not equaled in commercial practice.

Shown in Figure 1.4.1 is a typical washability analysis as presented in the sulfur reduction potential study. In addition to giving weight and Btu recoveries, Btu/lb, and ash and sulfur percentages at the various separation densities, a subprogram calculates the pounds of SO_2 per million Btu and then interpolates the results to show which values, if any, will meet the EPA new-source emission standard of 1.2 lbs SO_2/MM Btu.

Results from this study are subdivided into the following coal producing regions:

- Northern Appalachian Region
- Southern Appalachian Region
- Eastern Midwest Region
- Western Midwest Region
- Western Region

In the Northern Appalachian region, to which this paper is addressed, 227 coalbed samples were collected: from Maryland (34), Ohio (58), Pennsylvania (103), and northern West Virginia (32). The average raw coal of the region contained 15.1 percent ash, 2.01 percent pyritic sulfur, 3.01 percent total sulfur, and 12,693 Btu per pound, which would produce 4.8 pounds SO_2/MM Btu fired at the powerplant.

As shown in Figure 1.4.2, crushing to 14-mesh and washing at 1.60 specific gravity would provide an average pyritic sulfur reduction of 65 percent and a total sulfur reduction of 41 percent, which would result in an SO_2 emission reduction of 46 percent.

Figure 1.4.3 shows that only 4 percent of the raw coal samples as mined could meet the current EPA emission standard of 1.2 pounds SO_2/MM Btu. However, 12 percent of the samples would comply at a Btu recovery of 90 percent when crushed to 1½-inch top size, and 31 percent would comply at a Btu recovery of 50 percent when crushed to 14-mesh top size. At a less stringent emission standard of 2.0 pounds of SO_2/MM Btu, 15 percent of the raw coal samples would meet this standard with no preparation, approximately 35 percent would comply at a 90-percent Btu recovery when crushed to 1½-inch top size, and about 70 percent would comply at a 50-percent Btu recovery when crushed to 14-mesh top size.

RESERVE BASE SURVEY

In 1975, the Eastern Field Operation Center of the Bureau of Mines published a two-volume compilation of coal reserve data [2, 3] for the United States as of January 1, 1974. The components of the reserve base, as defined by the Bureau and incorporated into the survey, are shown in Figure 1.4.4.

This Bureau of Mines study was initially funded by the U.S. Environmental Protection Agency. In 1972, the study was made a part of on-going Bureau programs.

Various State and Federal agencies have previously made coal resource and reserve estimates; however, because these estimates were often based upon different criteria and assumptions, the resulting reports varied widely in tonnage values. In contrast, the Bureau of Mines report contains determinations, developed by uniform criteria, of the location and extent of the reserve base of coal recoverable by today's mining methods. Data were compiled from a total of 281 sources which are referenced in the report.

The volume that covered the Eastern United States indicated a coal reserve base of 202.3 billion tons (Figure 1.4.5). Included in this estimate are bituminous coal (194.0 billion tons), anthracite (7.3 billion tons), and lignite (1.0 billion tons). The reserve base is divided into those coals minable by underground methods and those minable by surface methods (Figure 1.4.6). The reserve base minable by underground methods includes 161.5 billion tons of bituminous coal and 7.2 billion tons of anthracite. Lignite is not considered minable by underground methods. The reserve base minable by surface methods includes 32.5 billion tons of bituminous coal, 90 million tons of anthracite, and 1 billion tons of lignite.

Figure 1.4.7 shows the reserve base of bituminous coal for those states in the northern Appalachian region. The totals for West Virginia, however, include those counties in southern West Virginia that are considered to be part of the southern Appalachian region. The reserve base of bituminous coal in the northern Appalachian region (this excludes southern West Virginia) is 68.3 billion tons, which represents 35 percent of the total bituminous reserves of the Eastern United States.

As shown in Figure 1.4.8 (from RI 8680), the data are organized by state, county, coalbed, and rank. The coal reserve base was, through statistical probability, distributed by increments throughout the range of sulfur contents determined from coal quality data on file in the energy data bank maintained by the Bureau of Mines. Only raw coal sulfur analyses were collated with the reserve data to approximate the sulfur content of in-place coalbeds. The computer distribution included all surfur categories between the extremes of highest and lowest; no tonnages of coal were allotted to sulfur categories higher or lower than those levels actually observed. Distribution of the coal reserve base, by sulfur content, was based on the assumption that the quality of coal remaining in the ground is basically equivalent to that of the coal that has been mined.

EFFECT OF BENEFICIATION ON COAL RESERVES

Given the two sources of data described above, the obvious question arises as to what extent U.S. coal reserves can be upgraded by utilizing coal preparation techniques. The sulfur content of Eastern coals varies widely, ranging from a low of 0.3 percent to as much as 5.6 percent. In determining the potential of coal preparation to produce low-sulfur coal, however, the form in which sulfur occurs and its amenability to removal are as important as the amount present. Therefore, answering the question posed above requires intermeshing the two studies previously discussed in order to determine the tonnages that will exist in each sulfur category following various levels of coal preparation.

To carry out these calculations, it was necessary to make several assumptions. These include:

- For a given coalbed, the percent reduction in sulfur attributable to a given level of coal preparation is the same regardless of the raw coal sulfur content. Although this is only an approximation, it is borne out well by Bureau of Mines Report of Investigations RI 8118.
- The reserves listed as unknown (sulfur contents) in RI 8680 were considered to be distributed throughout the sulfur ranges in the same proportion as the remainder of the reserves in that same coalbed.

- In RI 8680 data do not exist for the sulfur contents in several of the coalbeds. Also, in RI 8118, sulfur reduction data are not available for every coalbed in the Northern Appalachian region. The percentages of the total reserves for which both sulfur content and sulfur reduction data are available amount to 93 percent in Maryland, 90 percent in Pennsylvania, 83 percent in Ohio, and 65 percent in northern West Virginia. It was, therefore, assumed that tonnages calculated based on reserves for which data were available could be multiplied by a factor (e.g., 100/90 in Pennsylvania) in order to represent the total reserves.

The calculations intermeshing the two studies were made according to the following procedure:

1. All reserve data for a given coalbed within a given state were compiled from RI 8680.
2. Since the upper sulfur limit is simply given as greater than 3.0 percent in RI 8680, the average percent sulfur greater than 3.0 was calculated by a mass balance.
3. Using RI 8118, percent sulfur reductions and percent yield for each coalbed in question were obtained by Lagrangian interpolation from the given data.
4. The sulfur reduction and yield percentages for each level of preparation were applied to the reserve data for each coalbed as compiled in step 1.
5. After the calculations were made for all reserves of known sulfur distribution, the new tonnage corresponding to each sulfur category was increased by the appropriate percentage as discussed in the third assumption above.
6. The tonnages thus calculated were summarized by States.

Figure 1.4.9 presents a partial summary of the data generated for Pennsylvania. The 10 sulfur categories listed in the reserve base study have been compressed into 3 in order to make the numbers more comprehensible. The tonnages cleanable to less than 0.85 percent sulfur (low-sulfur coal) are the ones of greatest concern because coals cleaned to this sulfur level will generally meet the EPA new-source emission standard of 1.2 pounds SO_2/MM Btu. Strictly speaking, for the coals of this region, those cleaned at 1.30 specific gravity will have sufficient Btu's per pound to meet the standard; those cleaned at 1.60 must generally contain no more than 0.82 percent sulfur. As shown in Figure 1.4.9, the present reserve base of coal in Pennsylvania that is less than 0.85 percent sulfur is 591.46 million tons. From reserves somewhat higher in sulfur, coal preparation produces substantial quantities of less than 0.85-percent-sulfur coal. For example, crushing to 1½-inch top size and cleaning at 1.60 specific gravity results in 1,968.56 million tons of this low-sulfur coal; i.e., over three times as much as presently available. However, crushing to 14-mesh top size and cleaning at 1.60 specific gravity would produce 4,774.77 million tons, an eightfold increase. As would be expected, the bulk of the reserves lie in the 0.85 to 3.0 percent sulfur range. From another point of view, 6 percent of Pennsylvania's coal reserves with a sulfur content greater than 0.85 percent can be upgraded to low-sulfur coal (<0.85 percent) by crushing to 1½-inch top size and washing at 1.60 specific gravity; 18 percent can be upgraded to low-sulfur coal by crushing to 14-mesh top size and washing at 1.60 specific gravity.

The tonnages, by sulfur category and extent of preparation, for the entire Northern Appalachian region are given in Figure 1.4.10. The present reserves with sulfur content less than 0.85 percent amount to 1,727.45 million tons. Crushing to 1½-inch top size and washing at 1.60 specific gravity yields 4,172.32 million tons of low-sulfur coal, which is 2.4 times the existing reserves. Crushing to 14-mesh top size and cleaning at 1.60 specific gravity would result in a total of 8,546.31 million tons of low-sulfur coal which is 4.9 times the present reserves. Four percent of the Northern Appalachian region reserves with a sulfur content greater than 0.85 percent can be upgraded to low-sulfur coal by crushing to 1½-inch top size and washing at 1.60 specific gravity; the percentage increases to 10 when crushing to 14-mesh top size and washing at 1.60 specific gravity.

Examination of the figures in Figure 1.4.10 reveals that crushing to 14-mesh top size and cleaning at 1.60 specific gravity results in a greater tonnage of low-sulfur coal than is obtained when cleaning at 1.30. This apparent anomaly is understandable, however, when one considers that all coals will reach a point of liberation beyond which the pyrite is totally free and washing at successively lower specific gravities will simply reduce the yield of clean coal.

Figures 1.4.11 and 1.4.12 show graphically the effect of crushing to various top sizes on the tonnages of low-sulfur coal potentially available in the Northern Appalachian region. In examining these figures, as well as those in Figure 1.4.9 and 1.4.10 to establish the benefits of coal preparation, it is necessary to keep several things in mind. First of all, even though the tonnages of low-sulfur coal (less than 0.85 percent sulfur)) resulting from coal preparation are a relatively small fraction of the total reserve base; they represent sizable quantities of coal, equivalent to many years of production at current and foreseen rates. Moreover, many powerplants constructed prior to 1975 can be brought into compliance with local emission standards by simply cleaning to an intermediate sulfur level.

In summary, coal preparation has the potential of providing sizable tonnages of coal that will meet the EPA new-source emission standards. In addition, for powerplants built prior to 1975, far greater quantities of coal can be burned after upgrading by coal preparation.

REFERENCES

1. Cavallaro, J. A., M. T. Johnston, and A. W. Deurbrouck. Sulfur Reduction Potential of the Coals of the United States: A Revision of Report of Investigations 7633. BuMines RI 8118, 1976. 323 pp.

2. Thomson, R. D., and H. F. York. The Reserve Base of U.S. Coals by Sulfur Content (In Two Parts) 1. The Eastern States. BuMines IC 8680, 1975. 537 pp.

3. Thomson, R. D., and H. F. York. The Reserve Base of U.S. Coals by Sulfur Content (In Two Parts) 2. The Western States. BuMines IC 8693, 1975. 322 pp.

STATE: PA (BITUMINOUS)
COUNTY: ARMSTRONG

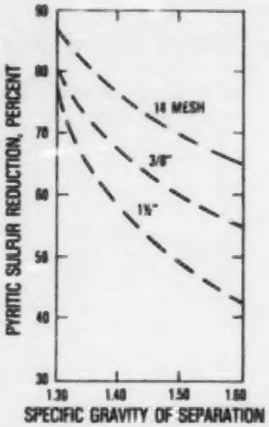
COALBED: UPPER FREEPORT
RAW COAL MOISTURE: 1.1%

CUMULATIVE WASHABILITY DATA
SAMPLE CRUSHED TO PASS 3/8 INCH

PRODUCT	RECOVERY, %		CALORIFIC CONTENT Btu/lb	ASH, %	SULFUR, %		EMISSION POTENTIAL lb SO_2/MM Btu
	WEIGHT	Btu			PYRITIC	TOTAL	
FLOAT - 1.30	47.3	57.9	14481	4.0	.17	.84	1.2
FLOAT - 1.40	67.9	81.5	14194	5.9	.24	.89	1.3
FLOAT - 1.60	77.6	91.2	13892	7.9	.35	.99	1.4
FLOAT - 1.90	82.9	95.2	13576	10.0	.45	1.07	1.6
TOTAL	100.0	100.0	11826	21.6	1.59	2.22	3.8
EPA STANDARD	57.4	69.5	14359	4.9	.20	.86	1.20

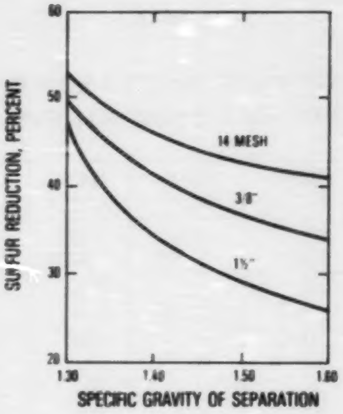
TYPICAL WASHABILITY ANALYSIS (REPORT OF INVESTIGATION 8118)

FIGURE 1.4.1



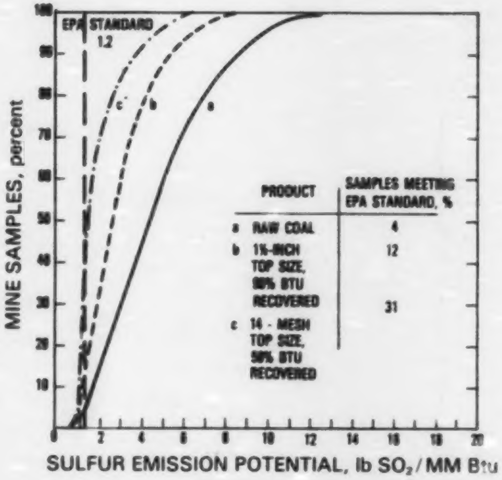
PYRITIC SULFUR REDUCTION FOR NORTHERN APPALACHIAN REGION COALS

Figure 1.4.2a



TOTAL SULFUR REDUCTION FOR NORTHERN APPALACHIAN REGION COALS

Figure 1.4.2b



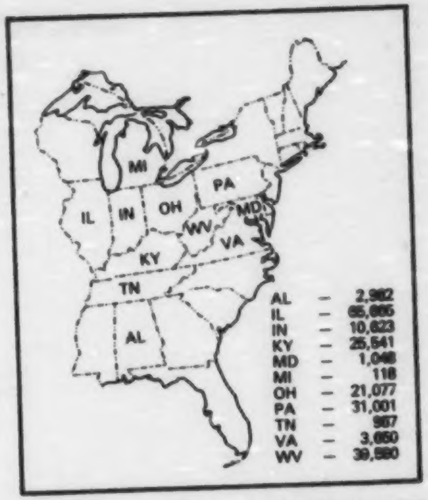
NORTHERN APPALACHIAN REGION COAL SAMPLES MEETING EPA SO_2 STANDARD

Figure 1.4.3

1. BITUMINOUS/ANTHRACITE COAL, 28 INCHES OR MORE THICK, TO DEPTHS OF 1,000 FEET
2. SUBBITUMINOUS COAL, 60 INCHES OR MORE THICK, TO DEPTHS OF 1,000 FEET
3. LIGNITE, 60 INCHES OR MORE THICK, TO DEPTHS OF 120 FEET (ONLY SURFACE MINING)

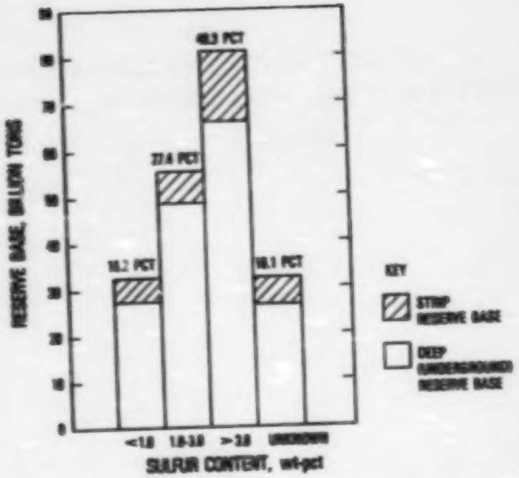
COMPONENTS OF THE RESERVE BASE

Figure 1.4.4


MI
PA
IL
IN
OH
MD
WV
VA
KY
TN
AL
AL — 2,982
IL — 65,665
IN — 10,623
KY — 25,641
MD — 1,048
MI — 118
OH — 21,077
PA — 31,001
TN — 987
VA — 3,050
WV — 39,580

COAL RESERVE BASE IN THE EASTERN UNITED STATES, Millions of Tons

Figure 1.4.5



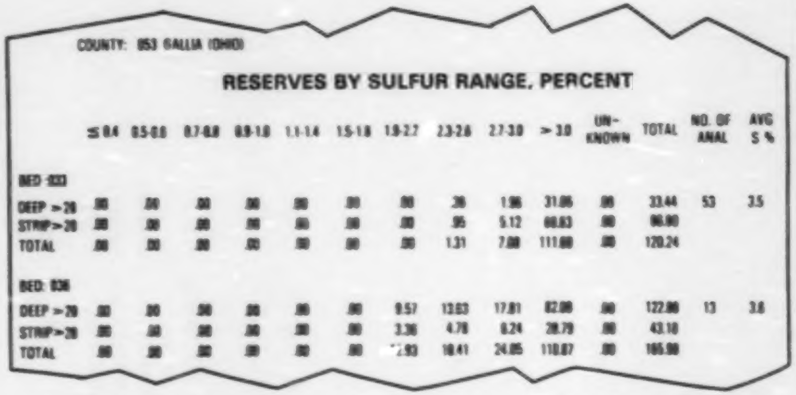
COAL RESERVE BASE IN THE EASTERN UNITED STATES

Figure 1.4.6

STATE	MINING METHOD	SULFUR CONTENT, WEIGHT-PERCENT				
		< 1.0	1.0-3.0	> 3.0	UNKNOWN	TOTAL
MARYLAND	DEEP STRIP	106.45 28.58	623.94 66.59	171.18 16.24	0 34.57	901.57 145.98
OHIO	DEEP STRIP	115.45 18.67	5,449.89 990.96	10,108.36 2,524.87	1,754.00 117.53	17,428.70 3,652.03
PENNSYLVANIA	DEEP STRIP	981.15 55.45	16,013.40 717.21	3,568.14 231.52	2,215.09 83.57	22,778.36 1,087.75
WEST VIRGINIA	DEEP STRIP	11,088.80 3,005.46	12,583.41 1,422.02	6,552.88 270.40	4,142.02 508.55	34,366.81 5,208.23
TOTAL	DEEP STRIP	12,288.05 3,108.34	34,670.09 3,187.58	20,401.58 3,043.03	8,112.01 745.62	75,474.51 10,084.57

RESERVE BASE OF NORTHERN APPALACHIAN BITUMINOUS COAL, Millions of Tons

Figure 1.4.7



COUNTY: 053 GALLIA (OHIO)

RESERVES BY SULFUR RANGE, PERCENT

	≤ 0.4	0.5-0.6	0.7-0.8	0.9-1.0	1.1-1.4	1.5-1.8	1.9-2.2	2.3-2.6	2.7-3.0	> 3.0	UN-KNOWN	TOTAL	NO. OF ANAL	AVG S %
BED: 033														
DEEP >28	.00	.00	.00	.00	.00	.00	.00	.36	1.96	31.06	.00	33.44	53	3.5
STRIP>28	.00	.00	.00	.00	.00	.00	.00	.95	5.12	80.83	.00	86.90		
TOTAL	.00	.00	.00	.00	.00	.00	.00	1.31	7.08	111.89	.00	120.24		
BED: 036														
DEEP >28	.00	.00	.00	.00	.00	.00	9.57	13.63	17.81	82.08	.00	122.88	13	3.8
STRIP>28	.00	.00	.00	.00	.00	.00	3.36	4.78	6.24	28.79	.00	43.10		
TOTAL	.00	.00	.00	.00	.00	.00	12.93	18.41	24.05	110.87	.00	165.98		

COMPUTERIZED OUTPUT OF TYPICAL RESERVE BASE
(REPORT OF INVESTIGATION 8680)

Figure 1.4.8

RESERVES BY SULFUR RANGE (MM OF TONS)			
COAL	*< 0.85% S*	*0.85-3.00% S*	*> 3.0% S*
RAW	591.46	19,008.89	3,885.63
CRUSHED TO 1½ INCHES TOP SIZE			
CLEANED AT 1.30	2,623.59	7,437.11	83.69
CLEANED AT 1.60	1,969.56	18,465.68	796.47
CRUSHED TO ⅜ INCH TOP SIZE			
CLEANED AT 1.30	3,826.91	7,539.97	68.39
CLEANED AT 1.60	3,341.73	17,148.11	583.03
CRUSHED TO 14 MESH TOP SIZE			
CLEANED AT 1.30	4,234.54	8,682.13	48.65
CLEANED AT 1.60	4,774.77	18,074.77	106.31

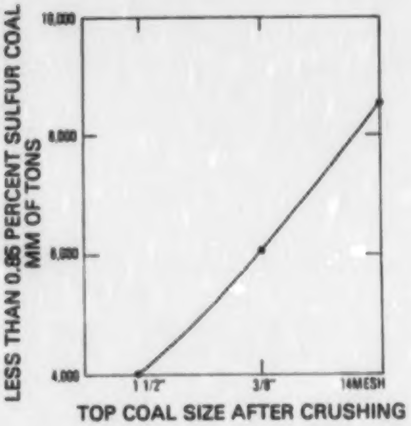
TONNAGES BY SULFUR RANGE
IN *PENNSYLVANIA*

Figure 1.4.9

RESERVES BY SULFUR RANGE (MM OF TONS)			
COAL	*< 0.85% S*	*0.85-3.00%S*	*> 3.0% S*
RAW	1,727.45	38,995.41	27,535.04
CRUSHED TO 1½ INCHES TOP SIZE			
CLEANED AT 1.30	4,237.93	20,398.17	537.29
CLEANED AT 1.60	4,172.32	43,308.58	14,184.45
CRUSHED TO ⅜ INCH TOP SIZE			
CLEANED AT 1.30	6,485.79	22,350.99	651.88
CLEANED AT 1.60	8,224.53	44,595.82	9,918.26
CRUSHED TO 14 MESH TOP SIZE			
CLEANED AT 1.30	7,136.62	21,881.77	385.59
CLEANED AT 1.60	8,546.31	45,873.05	5,956.40

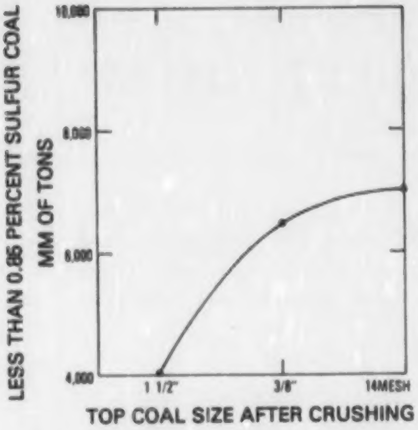
TONNAGES BY SULFUR RANGE
IN *NORTHERN APPALACHIAN REGION*

Figure 1.4.10



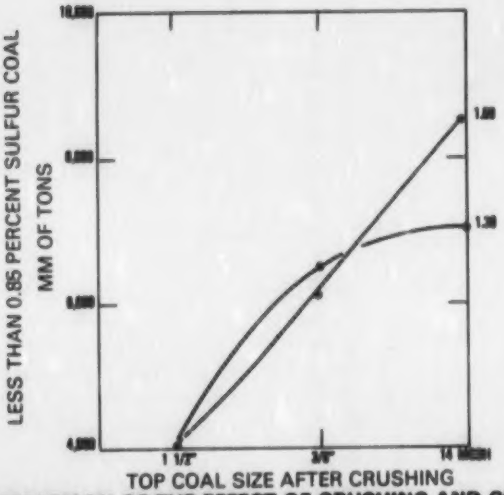
EFFECT OF CRUSHING AND CLEANING AT 1.60 SPECIFIC GRAVITY ON THE AVAILABILITY OF <0.85 PERCENT SULFUR COAL.

Figure 1.4.11



EFFECT OF CRUSHING AND CLEANING AT 1.30 SPECIFIC GRAVITY ON THE AVAILABILITY OF <0.85 PERCENT SULFUR COAL.

Figure 1.4.12



COMPARISON OF THE EFFECT OF CRUSHING AND CLEANING AT 1.60 AND 1.30 SPECIFIC GRAVITIES ON THE AVAILABILITY OF < 0.85 PERCENT SULFUR COAL

Figure 1.4.13

DESIGNING A REGIONAL ATMOSPHERIC CONTROL STRATEGY FOR ELECTRIC UTILITIES

Dr. Gerald A. Isaacs
Timothy W. Devitt
Ray W. Cunningham

INTRODUCTION

A significant amount of work is being conducted to demonstrate that physical coal cleaning can be used to reduce SO_2 emissions from coal-fired boilers. This paper addresses some of the factors that bear upon the viability of coal cleaning as an effective sulfur dioxide emission control measure. It presents recent data developed by PEDCo on an EPA sponsored study that investigates the potential role of coal cleaning in an SO_2 compliance strategy for selected power generating stations within EPA's Region IV. Some of the factors that should be considered in designing a regional control strategy utilizing coal cleaning, flue gas desulfurization (FGD), low sulfur coal, and redistribution of existing coal supplies are discussed; and an example is presented to show the effect of these factors.

WASHABILITY DATA

The theoretical limit to which any coal can be physically cleaned is established by the organic sulfur content of the coal. A washability analysis takes the form of size-gravity fractional analyses of appropriate coal properties; a washabililty curve can be constructed by starting with the cleanest fraction in terms of lbs SO_2 per million Btu and adding successively dirtier fractions. The resulting curve starts at zero Btu recovery and the organic sulfur content, and ends at 100 percent Btu recovery and the raw coal sulfur content. Figure 1.5.1 shows that a good empirical approximation to the curve is given by an equation of the form:

$$y = a + b x + c e^{d(100-x)}$$

where the coefficients a, b, c, and d are determined experimentally.

An estimate of washability in this form can be useful in determining the feasibility of cleaning a given coal to a prescribed SO_2 level. In the given example, it is evident that the coal from this mine cannot possibly be cleaned to meet an emission limitation of 3 lbs SO_2 per million Btu because of the high organic sulfur content of the coal (3.2 lbs SO_2/MM Btu). A four-pound limitation can be met if a 10 percent Btu loss can be tolerated. This loss can be reduced somewhat if a coal middlings fraction can be used economically at another power plant that is within or close to the area for which the regional strategy is being developed.

COST DATA

Among several investigations of the cost of pollution control conducted by PEDCo, two are especially appropriate to an SO_2 strategy optimization program. The first is a computerized program that estimates the installed capital and annualized costs for gas desulfurization systems. Input to these programs is specific design and operating information on each boiler for which controls are proposed. The second investigation resulted in a similar computer program that estimates the capital and operating costs for coal cleaning plants. This program calculates costs for a three-cleaning-circuit plant, with provision for two stages in the coarse-coal circuit.

Coal cleaning costs are a function of several variables including design of the coal cleaning circuits. The effects of plant size and economies of scale were investigated by simulating a specific plant configuration at several different throughput capacities. The results, presented in Figure 1.5.2, show that cleaning costs per unit of coal decrease with increasing plant size. Assuming an equation of the form:

$$y = a\,x^{b}$$

a least-squares best fit of the data resulted in the relationship:

$$y = 39\,x^{-0.38}$$

which agrees well with the traditional rule-of-thumb that plant cost bears a 0.6 power relationship to plant size. It appears that economies of scale are reasonably approached only for coal cleaning plants with capacities larger than about 500 tons of coal per hour.

A significant portion of the cost of coal cleaning is the heating value that is discarded in the reject circuit. Total Btu losses exceeding about 5 percent generally cannot be tolerated economically unless some of the potential Btu losses are recovered elsewhere in the system. If losses exceed that amount, coal cleaning ceases to be competitive with flue gas desulfurization. Therefore, the cost of Btu losses, as well as other operating maintenance and capital charges, must be and were added to the costs generated by our coal cleaning cost estimating program. Total costs, including lost heating value, were determined for a two-stage cleaning plant having an input capacity of 2,000 tons of coal per hour. The effects of coal price and recovery yield are shown in Figure 1.5.3. At a coal price of $1.00 per million Btu, the total cost of coal cleaning is doubled if the yield drops to about 92 percent, as compared with owning and operating costs only (100 percent yield).

LIMITATIONS AND DISADVANTAGES OF COAL CLEANING

The sensitivity to coal costs and yield has been cited as a major disadvantage of coal cleaning. However, to the extent that they consume energy, it is evident that all major pollution control processes are fuel-cost sensitive. The principal limitation of physical coal cleaning is that the degree of sulfur removal is theoretically limited to the proportion of pyritic sulfur in the coal. In practice, the limitations are even more stringent. For a typical coal it may be practical to remove only 20 to 40 percent of the sulfur by physical cleaning, whereas an FGD system may provide 85 percent SO_2 removal efficiency. The low efficiency of sulfur removal, therefore, greatly restricts the number of cases for which coal cleaning is economically feasible.

The sulfur and ash removed from the coal create special environmental problems at the coal cleaning site. Cleaning plant refuse, containing finely divided sulfurous materials, poses significant problems of water pollution potential. Proper disposal is an important factor to be considered in evaluating the feasibility of coal cleaning.

It has been suggested that the cleaning process may create problems for wet bottom boilers because of elevation of ash fusion temperatures. Further testing with specific boiler designs is needed to resolve this issue. It has also been suggested that the lower sulfur content of the cleaned coal may adversely affect electrostatic precipitator performance. In the cases that we have investigated, the sulfur levels have not been reduced enough to create true low-sulfur coals; we believe that the reduced ash loadings to the boilers will offset any deterioration of precipitator efficiency that may occur due to lowered sulfur content.

BENEFITS OF COAL CLEANING

In the cases where coal can be physically cleaned to meet SO_2 emission restrictions, the coal cleaning strategy should be compared with other control strategies; i.e., the use of alternative coal supplies and the use of an FGD system. A comparison of coal cleaning and use of alternative coal is relatively straightforward, consisting essentially of comparing the cost of delivered cleaned coal with the cost of alternative coals, other factors being equal.

In situations where coal cleaning is technologically and economically feasible, the percent of sulfur removal that is required must necessarily be relatively low. Since FGD systems are capable of removing at least 85 percent of the SO_2 that is generated, an FGD system need clean only a fraction of the flue gas at a power station to match the sulfur removal capabilities of coal cleaning. In such a situation, although the apparent costs of coal cleaning and FGD may be essentially equal, several factors favor the use of coal cleaning over FGD systems.

A coal cleaning system tends to produce a relatively consistent low-ash fuel that enhances the operation of the boiler and produces a minimum of refuse at the power plant. In contrast, an FGD system can derate power system output and produces sludge that must be handled on-site.

In cases where the annualized costs for coal cleaning are equal to the annualized costs for an FGD system, the coal cleaning option may be preferable for a utility since it is less capital intensive. For comparative purposes, two strategies were investigated for five power stations in Region IV, one using FGD exclusively, and the other using relatively extensive coal cleaning. Figure 1.5.4 shows that the ratio of capital to annualized cost for an FGD system ranges from 3.0 to about 3.2, whereas with coal cleaning the ratio ranges from 1.1 to 2.6. The difficulty of obtaining capital gives the utilities an incentive to opt for coal cleaning over FGD.

We have also concluded that firing cleaned coal can result in lower costs for boiler maintenance. Our studies indicate that for some coals it may be possible to remove 12 percent of the weight of the coal while reducing the total Btu content by only 5 percent. At the same time, the ash reduction on a mass basis would total 47 percent. Since pulverizer wear and maintenance are closely related to the ash content of coal, it is expected that pulverizer and ash handling equipment maintenance would be reduced considerably with the burning of cleaned coal. Ash erosion and corrosion of boiler tubes and flues would also be reduced — beneficial effects that would not accrue in an FGD operation.

We have accumulated some data that relate boiler outage rates to coal properties. Data such as those shown in Figure 1.5.5, support our conclusion that certain types of boiler failures may be reduced significantly if coal ash and sulfur contents are reduced via coal cleaning. Several similar relationships between boiler failures and average annual sulfur and ash contents were determined to be significant at a 90 percent confidence level. Cleaned coal could thus improve boiler availability and the resulting capacity factor, since forced outages as well as maintenance costs would be reduced.

In boiler operation, fluctuations in coal quality often make it necessary to increase excess air rates, thus reducing boiler efficiency. The product of a coal cleaning plant is a more consistent fuel than raw coal, and this fuel consistency thereby reduces excess air requirements. The lower ash content in cleaned coal also reduces thermal losses in the boiler ash. The net result is an improved heat rate, at least in terms of the coal that is fed to the boiler. This increase helps to defray part of the total cost of coal cleaning.

At various power plants it has become necessary to derate boiler capacities because of deterioration of coal quality. It seems reasonable that coal cleaning could be used to upgrade fuel quality so that some boilers could be uprated, at least where the unit capacities are not turbine-limited.

REGIONAL STRATEGY ELEMENTS

Designing a regional compliance strategy is considerably more complex than planning for a single plant. A region suitable for a region-wide compliance strategy should have the following characteristics:

- Contain several power plants whose mangements are willing to work together to formulate a combined SO_2 emission compliance strategy. This entails coordination of coal procurement activities, joint ownership of preparation plants, and equitable cost distribution.
- Individual power plants within the region would not all be subject to the same SO_2 emission restriction.
- Access to multiple coal supplies.

By effectively pooling their joint coal resources, the participants in a regional strategy may be able to attain all applicable emission requirements at a lower total overall cost than if each participant adopts an individual compliance strategy. The regional strategy entails a mix of controls which may include the use of joint coal suplies, coal cleaning plants, and flue gas desulfurization equipment.

INPUT DATA FOR A REGIONAL COMPLIANCE STRATEGY

An effective regional strategy can be developed only if sufficient data are availble to allow detailed problem definition and analysis. These data can then be reduced to yield an optimum solution. The following data are required:

- Coal costs, FOB mine — $/MM Btu
- Coal properties — Btu/lb, % sulfur
- Coal cleaning costs — $/kWh output
- Coal cleaning curves — lb SO_2/MM Btu vs % Btu recovery
- Coal supply capacities — MM Btu/week
- Transportation costs — $/MM Btu
- FGD costs — $/kWh
- FGD SO_2 removal — percent
- Fuel requirements — MM Btu/week
- SO_2 regulations — lb SO_2/MM Btu
- Power demand — peak kW, kWh/week
- Station heat rates — Btu/kWh

COAL CLEANING APPLICATIONS AS PART OF A REGIONAL STRATEGY

An example of the use of coal cleaning, flue gas desulfurization, low sulfur coal, and fuel redistribution in a regional strategy is illustrated in this section. The regional strategy considered a number of coal-fired power plants in EPA's Region IV. The plants derive virtually all of their coal from mines in Ohio, Illinois, Kentucky, Tennessee, and Alabama. SO_2 restrictions at the plants range from 1.2 lbs SO_2 per million Btu to 5.2 lbs SO_2 per million Btu. The coal transportation system includes barge, rail, and truck modes. Plant capacities range from approximatey 250 MW to 2,600 MW.

This strategy was compared with the use of FGD at all plants where SO_2 control is required. Figure 1.5.8 shows that fuel redistribution eliminates incremental coal costs at Plants 1, 3, and 5. For this study incremental transportation costs were assumed to be negligible because of the regional transportation cost structure. Costs increased at Plants 7, 8, 10, and 11, where FGD systems are used in conjunction with uncleaned coal because of the stringent SO_2 emission regulations. Coal cleaning plants are assumed for Plants 4 and 9. Cost of the combined strategy is about 19 percent lower than the FGD strategy on an annual basis; it is 21 percent lower on a capital investment basis.

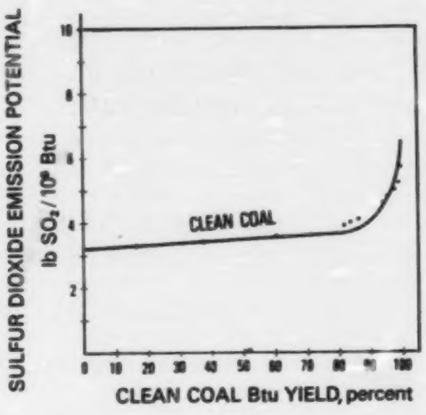
CONCLUSIONS

Coal cleaning techniques have been utilized for several years, and many coal cleaning plants are currently in operation. Rather conventional coal cleaning methods can be used to produce coals that comply with SO_2 regulations in some cases. The principal advantages of coal cleaning are reduced maintenance costs, increased boiler availability, boiler rating increases, and better boiler heat rates. These beneficial effects tend to offset the costs of the cleaning process.

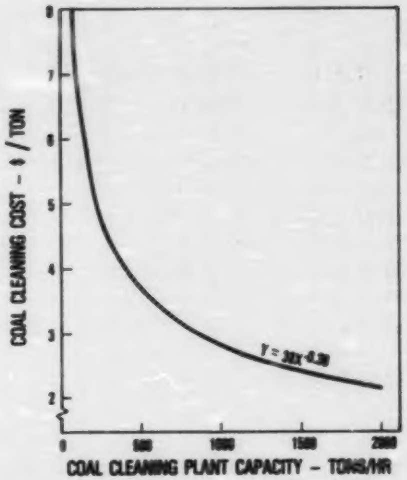
The benefits and disadvantages of coal cleaning strategies are not yet fully documented. There is a possibility that coal cleaning may alter ash characteristics enough to create firing difficulties with wet-bottom boilers. It has been suggested also that ESP performance may deteriorate, but since sulfur removal by coal cleaning is moderate (typically less than 50 percent), this effect should be insignificant; the reduced ash loading to the ESP would probably more than compensate for any loss in efficiency due to slightly increased fly ash resistivity. Pollution problems resulting from coal cleaning will mainly occur at the cleaning plant in the form of liquid and solid wastes.

It has become apparent that coal cleaning may be viable for reducing SO_2 emissions at certain power plants, especially those where emission requirements are not especially severe with respect to the coal that is presently fired. Where high SO_2 removal efficiencies are required, FGD systems are more economical because fuel loss penalties become excessive for coal cleaning plants.

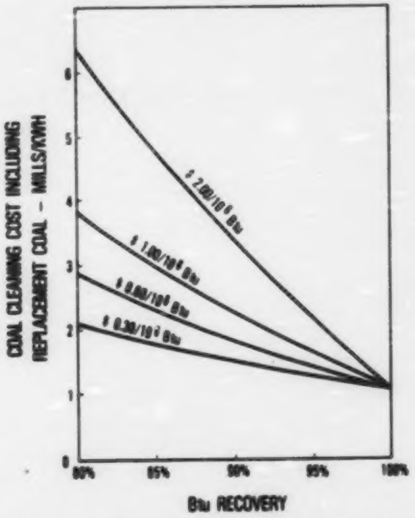
The concept of using coal cleaning as part of an overall SO_2 compliance strategy seems to have merit where several power plants in an area are subject to various SO_2 regulations. A preliminary study of selected power generating stations within EPA's Region IV indicates that coal cleaning for two of nine plants can be used in conjunction with fuel redistribution to optimize compliance costs for the entire system. This strategy is about 20 percent less expensive, not including potential benefits from reduced maintenance, etc., than if FGD were used at all plants now out of compliance.



COAL CLEANING YIELD CURVE
SINCLAIR MINE — SEAM 9 — UNDERGROUND
Figure 1.5.1



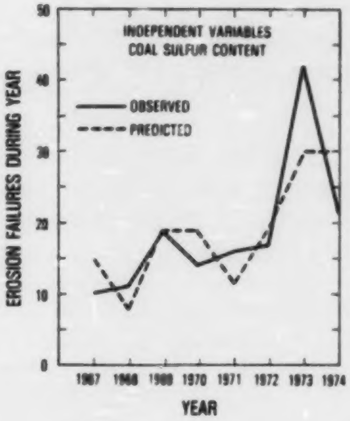
COAL CLEANING COST-PLANT SIZE RELATIONSHIP
Figure 1.5.2



TOTAL COST FOR TWO-STAGE COAL CLEANING AS A FUNCTION OF COST AND Btu RECOVERY EFFICIENCY
Figure 1.5.3

	CAPITAL COST $(10⁶)		ANNUAL COST $(10⁶)		RATIO OF COST CAPITAL TO ANNUAL	
PLANT	FGD	CC	FGD	CC	FGD	CC
1	27.9	18.4	8.6	10.8	3.2	1.7
3	52.0	29.4	16.2	26.6	3.2	1.1
4	82.3	45.9	27.6	18.0	3.0	2.6
5	36.0	24.7	11.1	19.1	3.2	1.3
9	53.7	38.9	17.8	19.8	3.0	2.0

CAPITAL INTENSITY COMPARISON — FGD AND COAL CLEANING
Figure 1.5.4



EROSION FAILURES — PLANT 8

Figure 1.5.5

- MANAGEMENT COOPERATION BY SEVERAL POWER PLANTS FOR IMPLEMENTATION OF A COMBINED POLLUTION CONTROL STRATEGY.
- EXISTENCE OF VARIOUS SO_2 RESTRICTIONS AMONG COOPERATING POWER PLANTS.
- ACCESS TO VARIOUS COAL SUPPLIES.

STRATEGY ELEMENTS FOR A REGIONAL CONTROL

Figure 1.5.6

- COAL COSTS, FOB MINE - $/$10^6$ BTU
- COAL PROPERTIES - BTU/LB, PERCENT SULFUR
- COAL CLEANING COSTS - $/KWH OUTPUT
- COAL CLEANING CURVES - LB SO_2 /10^6 BTU VS PERCENT BTU RECOVERY
- COAL SUPPLY CAPACITIES - 10^6 BTU/WEEK

DATA REQUIREMENTS FOR A REGIONAL CONTROL

Figure 1.5.7a

- FGD COSTS - $/KWH
- FGD SO_2 REMOVAL - PERCENT
- FUEL REQUIREMENTS - 10^6 BTU/WEEK
- POWER DEMAND - PEAK KW, KWH/WEEK
- SO_2 REGULATIONS - LB SO_2 / 10^6 BTU
- STATION HEAT RATES - BTU/KWH
- TRANSPORTATION COSTS - $/$10^6$ BTU

DATA REQUIREMENTS FOR A REGIONAL CONTROL
(Continued)

Figure 1.5.7b

PLANT	CAPITAL COST $(MM)		ANNUAL COST $(MM)	
	FGD	BEST STRATEGY	FGD	BEST STRATEGY
1	27.9	-	8.6	-
2	-	-	-	-
3	52.0	-	16.2	-
4	82.3	45.9	27.6	18.0
5	36.0	-	11.1	-
6	-	-	-	-

COMPARISON OF COSTS FOR FGD CONTROL WITH COSTS FOR A COMBINED STRATEGY USING FGD, COAL CLEANING AND FUEL REDISTRIBUTION

Figure 1.5.8a

PLANT	CAPITAL COST $(MM)		ANNUAL COST $(MM)	
	FGD	BEST STRATEGY	FGD	BEST STRATEGY
7	99.6	102.6	30.3	31.2
8	99.7	106.8	31.1	33.1
9	53.7	35.3	17.8	16.8
10	114.4	116.1	36.0	36.5
11	124.2	136.5	38.3	41.6
TOTAL	689.8	217.0	543.2	177.2

COMPARISON OF COSTS FOR FGD CONTROL WITH COSTS FOR A COMBINED STRATEGY USING FGD, COAL CLEANING, AND FUEL REDISTRIBUTION

(Continued)

Figure 1.5.8b

1. TECHNOLOGY IS HERE-NUMEROUS COAL CLEANING PLANTS ALREADY IN OPERATION.
2. BENEFITS AND DISADVANTAGES HAVE NOT BEEN FULLY DOCUMENTED.
3. COAL CLEANING IS VIABLE ONLY FOR SPECIFIC PLANTS AND SYSTEMS.
4. THE CONCEPT OF USING COAL CLEANING AS PART OF AN OVERALL STRATEGY INCORPORATING OTHER TECHNIQUES WITHIN THE SYSTEM SEEMS TO HAVE SPECIAL MERIT.

CONCLUSIONS IN DESIGNING A REGIONAL ATMOSPHERIC CONTROL STRATEGY FOR ELECTRIC UTILITIES

Figure 1.5.9

PART II. CLEANING PROCESSES

IMPLEMENTATION OF COAL CLEANING FOR SO_2 EMISSION CONTROL

James D. Kilgroe

INTRODUCTION

Sulfur oxide air pollution emissions from coal combustion exceeded 20.5 million tons in 1974. With the increasing use of coal as an energy source, improved methods are needed for the control of this pollutant. Major strategies for the control of SO_2 emissions include the use of coal cleaning, the combustion of coal in chemically active fluidized beds, the removal of pollutants by flue gas scrubbing and the generation of clean synthetic fuels. An economically attractive control strategy is coal cleaning. This paper presents the current status of coal cleaning technology, and discusses barriers which must be overcome before this technology can be widely implemented for SO_2 emission control.

TECHNICAL STATUS

Coal Cleanability

The sulfur content of coal normally ranges from less than 1 to more than 7 percent. Sulfur appears in coal in three forms: mineral sulfur in the form of pyrite (FeS_2), organically bound sulfur, and trace quantities of "sulfate" sulfur. Sulfate sulfur occurs in coal as a result of the attack of oxygen on the mineral pyrite. It is soluble in water and can be removed in wet coal preparation plants. Organic sulfur occurs as part of the organic coal structure and cannot be removed by physical coal preparation techniques. Pyrite occurs in coal seams in sizes ranging from small discrete particles to large lumps. It can be found intimately dispersed in the coal substance, in bands, in layers, or in large pieces.

Physical preparation or cleaning techniques are capable of removing varying fractions of the pyritic sulfur as determined by the properties of each coal. Chemical processes are capable of removing over 95 percent of the pyritic sulfur and up to about 70 percent of the organic sulfur.

Laboratory float-sink studies have been performed on over 455 U.S. coals to determine their physical cleanability.(1) The samples tested were from mines in the six major coal producing regions of the U.S., the mines which provide more than 70 percent of the coal used in U.S. utility boilers.

The results of these float-sink tests indicate that in general pyrite removal increases with reduced particle size and specific gravity of separation. This fact is extremely important. It implies that to enhance pyritic sulfur removal more of the coal must be crushed and processed at finer particle sizes than historically practiced in coal preparation. A second important fact determined by these studies is that the final sulfur levels to which coals can be cleaned vary from coal region to coal region and from one coal bed to another within the same region (coal cleanability also varies to a lesser extent from location to location within the same mine). These differences in physical cleaning potential are the result of variations in the organic and pyritic sulfur levels and the morphology of the coal-pyrite matrix.

Sulfur removal by chemical methods is dependent upon coal properties and process conditions — time, pressure, temperature, and chemical reagents. A number of experimenters have studied these relationships(2,3). In other instances the availabililty of information is limited because it is considered to be proprietary. Process costs will probably limit the amount of sulfur which can be removed to about 95 percent of the pyritic sulfur and 40 percent of the organic sulfur.

Figure 2.1.3 presents parametric relationships between the degree of cleaning (pyritic and organic sulfur reduction), the sulfur level of the cleaned coal, and the percentage of utility coals which can be cleaned to a specified sulfur content.

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Status of Coal Cleaning Technology

Coal preparation processes for steam coal are oriented toward the removal of ash and mining residue. Chemical coal cleaning is in the early stages of development and it is estimated that a commercial plant could not be put into operation for at least 5 to 10 years. Figure 2.1.4 summarizes several chemical coal cleaning processes now under development. The remaining discussions will deal primarily with the use of physical coal cleaning as an SO_2 pollution control method.

The physical removal of pyritic sulfur from steam coal has not been commercially used as a method of SO_2 emission control. The physical removal of pyrite from many coals will require crushing to fine particle sizes prior to separation. Separation at these fine sizes, while not impossible, represents a shift to a mix of equipment and operating conditions which are different from those traditionally used for steam coal preparation. Dewatering and drying of a large percentage of fine coal may be required for many of the new plants.

The variabililty of sulfur forms within a coal bed or mine presents a special problem which will require the development of improved technology if coal cleaning is to be used for SO_2 emission control. Methods are needed for controlling the sulfur variation in the plant feed and process instrumentation is needed to control the product sulfur level.

The coal preparation plant performance in removing pyritic sulfur can be seriously affected by wide variations in feed coal properties. Development of mining and blending schemes to minimize the pyritic sulfur variations in the feed coal will be needed to insure a product coal which consistently meets fuel sulfur requirements. Currently there is little published data on the variabililty of fuel sulfur forms in coal beds. The effects of mining, blending, and preparation plant operations in "averaging out" the cleaned coal sulfur level are unknown. Because of these factors, the cleaning plant must now be designed to remove sufficient pyritic sulfur so that even at peak raw coal sulfur levels (both organic and pyritic), the product coal sulfur will be maintained below that required by the fuel sulfur emission regulation. This approach may not be practical in some cases as it would require the reject of large quantities of fuel which do not exceed the emission regulation.

A long term objective would be to develop process instruments and controls which could be used to adjust plant operating conditions in response to the changes in the feed coal sulfur content. This method of control would allow optimization of sulfur removal and Btu recovery. Unfortunately instruments which can be used for a real time determination of coal sulfur, ash, and Btu values are not commercially available.

Options for Using Coal Cleaning

Physical coal cleaning can be used on a limited number of U.S. coals to meet federal new source performance standards (NSPS) for steam generators. Moreover a large number of coals can be physically cleaned and used:

- To meet stringent state SO_2 emission standards.
- In conjunction with flue gas desulfurization (FGD) to lower emission control costs.
- To produce a multiplicity of product coals, each with a different fuel sulfur value.

Only 14 percent of the 455 U.S. coals tested by the Bureau of Mines are capable of meeting NSPS standards without cleaning(¹). Physically cleaned at a top size of 1½-inch, and with a Btu recovery of 90 percent (10 percent of the heat from the mined coal would be lost), a total of 24 percent of these coals, could meet NSPS. The percentage of coal which will be cleaned to NSPS levels could be increased by either a reduction in the particle size of coal being cleaned or a reduction in the Btu recovery value of the cleaned product. In the latter case the reject coal could probably be used in a boiler with FGD.

A much larger percentage of coals is capable of meeting widely varying state standards. Figure 2.1.6 presents data on the amounts of pyritic sulfur which can be removed from coal samples from six regions by crushing to a ⅜-inch top size and by separating at a specific gravity of 1.6. As illustrated the average fuel sulfur values for the cleaned coals from these six regions range from 1.3 to 5.5 lbs SO_2/mm Btu. In all cases the Btu recovery exceeds 92 percent. Many states have emission regulations which range from 2.0 to 5.0 lbs SO_2/mm Btu and a large portion of the tested coals can be cleaned to meet these regulations. Figure 2.1.7 presents the relationship between selected cleaning conditions and the number of samples which can be cleaned to meet specific emission standards.

The use of physical coal cleaning in combination with flue gas desulfurization (FGD) represents an approach where the advantages of each technique can be used to minimize emission control costs while permitting the most effective use of U.S. coal resources. A recent study on the use of a combination of physical coal cleaning and flue gas desulfurization shows significant economic advantages to this combined pollution control method(4). In 36 case studies in areas where local regulations for SO_2 emissions vary from 1.2 to 1.6 lbs SO_2/mm Btu, the cost of using a combination of conventional coal cleaning and flue gas desulfurization was 2 to 55 percent lower than flue gas desulfurization alone for new plants, and 10 to 60 percent lower for existing plants. The arithmetic average for the cases cited showed costs which were about 30 percent lower for new plants and 40 percent lower for existing plants.

An alternative strategy which would make greater utilization of our coal resources would be to prepare (clean) coal in such a fashion that it is divided into a number of fractions — each with a different sulfur content. Each coal fraction could thus be used in a different boiler to meet different sulfur emission regulations. The multi-stream coal cleaning strategy being used at the Pennsylvania Electric Co. Homer City Plant for the physical desulfurization of coal is an example of this approach to pollution control. At the Homer City plant, the product coals will include 800 tph of coal with an equivalent sulfur emission value of 4.0 lbs SO_2/mm Btu and 400 tph of coal with a sulfur emission value of 1.2 lbs SO_2/mm Btu.

The production of multiple coal streams in commercial plants to produce fuel for several non-utility markets has significant potential. Mine-mouth preparation plants of advanced design could produce a number of product coals with different fuel sulfur levels. The lower sulfur fuels could be sold for use in small commercial or industrial boilers in which the scale of operation makes FGD uneconomical. The higher sulfur coals could be used in existing boilers which are not subjected to stringent standards or they could be burned in large boilers equipped with FGD systems.

BARRIERS TO THE IMPLEMENTATION OF COAL CLEANING TECHNOLOGY

Technical and Regulatory Uncertainties

There is still considerable economic risk related to technical and regulatory uncertainties which act as effective barriers to the implementation of physical coal cleaning as an SO_2 emission control strategy. The use of coal cleaning as a tool for meeting SO_2 emission regulations is based upon engineering and scientific judgment. This pollution control strategy has been used only in a few isolated cases, generally with easily cleaned coals. The unknown economic risks are primarily related to the requirement for meeting consistent fuel sulfur specifications. In a given plant, the mix of equipment or the process controls may not prove to be adequate to consistently remove pyritic sulfur to the required degree. Technical solutions to this problem would involve a number of economically unattractive alternatives:

- Adjust the preparation plant operating conditions in a manner which would reduce the fuel recovered from the plant feed.
- Make extensive equipment modifications.
- Add a partial FGD system to the boiler.

A great deal of this economic risk could be reduced by more flexible regulatory activities. The modification of existing emission regulations to permit emissions to be averaged over a moderate time period, say 8 hours, would greatly alleviate this risk. In cases where a mix of emission regulations apply to a single site, the use of a site average emission regulation could, in some instances, reduce control costs and risks.

Other technical or regulatory uncertainties include:

- The costs of pollution control requirements for advanced coal preparation plants.
- Changes in boiler operating and maintenance costs which result from the firing of cleaned coal.
- The effects of firing cleaned coal on the performance of electrostatic precipitators.

Extensive commercialization of physical coal cleaning for SO_2 emission control probably cannot be expected until these uncertainties are resolved.

Institutional and Economic Barriers

A number of institutional and economic barriers block implementation of the use of coal cleaning for SO_2 emission control. Among these barriers are existing investments and contracts, the dependency of the utility industry upon other organizations for its fuel supply, a limited supply of personnel familiar with coal cleaning, and the high cost of capital.

Vertical integration in the utility industry is not common. Few utilities own their own fuel resources. A large percentage of coal resources are owned by railroads, steel companies, coal companies, oil companies, and private owners. The common practice is to obtain coal through short or long term contracts. Further, the coal supplier has traditionally cleaned his coal primarily to remove ash and mining residue. In today's coal market there is not a clear recognition by the supplier of clear cost differentials based upon the coal sulfur levels. The supplier thus does not have an economic incentive to clean his coal with the objective of removing sulfur. While the coal industry enjoys a healthy market with high profits, investment is largely directed to expansion of capacity through mechanization, and to the use of goods and services needed to meet new mine safety and environmental regulations. Incentives for coal cleaning in the coal industry must come from the market (utilities), regulatory activities, or tax laws. None of these incentives is now operable.

Utilities can contract with coal suppliers for coal cleaning, or they can clean the coal themselves. However, in some instances current investments and contract commitments are disincentives to this action. An example of these disincentives is the extensive use of Pittsburgh bed coal by utilities in the Appalachian region. A number of coal companies have high investments in existing mines and a number of utilities have long term contracts for this Pittsburgh bed coal. This coal is high in organic and pyritic sulfur and cannot be easily used to meet emission standards with little or no cleaning. However, the costs of breaking existing contracts, developing new mines, and constructing coal preparation plants may be more costly than the use of FGD on either existing or new generating units.

Another problem in implementing coal cleaning technology is that of identifying coal reserves that are adaptable to physical cleaning. Although cleanability studies have been performed by the Bureau of Mines, their work has been restricted to coals available from existing mines. Cleanability data are also needed on coal seams and geographic areas not currently developed. In this way promising new resources can be identified for development.

Difficulties which utilities may experience in raising capital may also serve as a barrier to implementation. Investors may be reluctant to support the capitalization of coal cleaning facilities because of the technical and regulatory uncertainties involved. Existing tax credits for equipment depreciation may also favor FGD over coal cleaning. Low interest rate government loans, positive environmental regulations, and modified tax laws could eliminate this economic barrier.

The lack of familiarity of the utility industry with coal cleaning as a pollution control may also serve as barrier to implementation. New technology is adopted in an industry only after it has been adequately demonstrated and accepted as a viable technology by a majority of the industry members. This barrier to implementation can best be overcome by joint government-industry research, development and demonstration (RD&D) activities. The utilities involved in this RD&D activity must be deeply involved and must eventually be committed to the development of new technology for the entire industry. The utility industry has not been oriented toward RD&D, and the development of government/industry teams is difficult. Current economic limitations on utility and government manpower available for RD&D compound this difficulty.

CONCLUSIONS

Physical coal cleaning can be used to meet a variety of state and federal SO_2 emission regulations, singly or in combination with flue gas desulfurization. There is an increasing awareness by the coal and utility industries of coal cleaning as a method of SO_2 control. However, this technology will not be widely used as pollution control strategy until a number of technical, regulatory, and institutional problems are resolved. They include:

- The determination of the performance and costs of coal preparation equipment and processes in removing sulfur.
- The development of improved methods for controlling the sulfur levels in coal produced by coal preparation plants.
- A clear acceptance by industry and regulatory agencies of this pollution control strategy.

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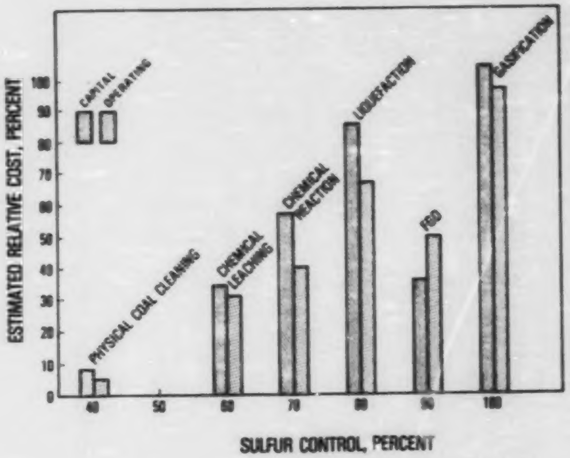
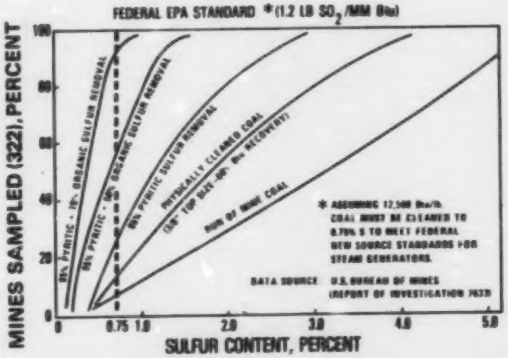
4. Aresco, S. J., L. Hoffman, and E. C. Holt, Jr. Engineering/Economic Analyses of Coal Preparation with SO_2 Cleanup Processes for Keeping Higher Sulfur Coals in the Energy Market, Preliminary Report on U.S. Bureau of Mines contract J0155171, The Hoffman-Munter Corporation, Silver Spring, Maryland, June 1976.

- TOTAL SULFUR AND SULFUR FORMS
  - ORGANIC SULFUR
  - PYRITIC SULFUR
- PHYSICAL AND CHEMICAL CHARACTERISTICS OF COAL-MINERAL MATRIX
  - SIZE AND DISTRIBUTION OF PYRITE
  - TOTAL MINERAL MATTER
  - HEAT CONTENT

PHYSICAL AND CHEMICAL CLEANABILITY
Figure 2.1.1



COSTS FOR VARIOUS SULFUR POLLUTION CONTROL METHODS
Figure 2.1.2



POTENTIAL LEVELS OF DESULFURIZATION FOR U.S. UTILITY COALS
Figure 2.1.3

PROCESSES UNDER DEVELOPMENT	DESCRIPTION	MAX. SULFUR REDUCTION, PERCENT		STATUS
		PYRITIC	ORGANIC	
ARCO	CATALYTIC DEMETALLIZATION	95	40	LABORATORY EXPERIMENTS
BATTELLE HYDROTHERMAL	CAUSTIC LEACHING [NaOH-Ca(OH)$_2$]	95	40	0.25 tpd MINI-PLANT
ERDA, BRUCETON, PA	OXI-DESULFURIZATION (AIR-STEAM)	99	40	LABORATORY EXPERIMENTS; DESIGN OF CONTINUOUS UNIT
TRW	AQUEOUS FERRIC SULFATE LEACHING [$Fe_2(SO_4)_3$]	95	NIL	LABORATORY EXPERIMENTS; CONSTRUCTION OF A 667LB/HR TEST UNIT

STATUS OF SELECTED CHEMICAL TREATMENT PROCESSES
Figure 2.1.4

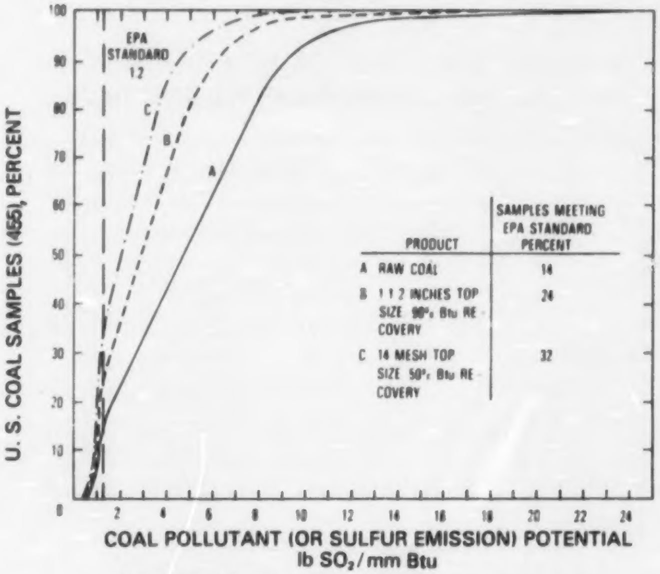
CURRENT TECHNOLOGY

- USED COMMERCIALLY FOR REMOVAL OF ASH AND MINING RESIDUE
- INCREASED RECOGNITION OF POTENTIAL USE FOR SO_2 EMISSION CONTROL
- CONSTRUCION OF A 1200 tph PLANT AT HOMER CITY, PA. FOR SO_2 EMISSION CONTROL

DEVELOPMENT NEEDS

- OPTIMIZE EQUIPMENT AND CIRCUITS FOR PYRITE REMOVAL
- PROCESS CONTROLS
- DETERMINATION OF COSTS

STATUS OF PHYSICAL COAL CLEANING
Figure 2.1.5



EFFECT-OF-CLEANING VARIABLE ON COAL POLLUTION POTENTIAL
Figure 2.1.7

CUMULATIVE ANALYSES OF FLOAT 1.90 PRODUCT FOR 3/8 TOP SIZE

COAL REGION	NO. SAMPLES	PERCENT Btu RECOVERY	PERCENT ASH	PERCENT PYRITIC SULFUR	PERCENT TOTAL SULFUR	POUNDS SO /10⁶ Btu	CALORIFIC CONTENT, Btu PER POUND
NOTHERN APPALACHIAN	227	92.5	8.0	0.85	1.86	2.7	13,763
SOUTHERN APPALACHIAN	35	96.1	5.1	0.19	0.91	1.3	14,197
ALABAMA	10	96.4	5.8	0.48	1.18	1.7	14,284
EASTERN MIDWEST	95	94.9	7.5	1.03	2.74	4.2	13,138
WESTERN MIDWEST	44	91.7	8.3	1.80	3.58	5.5	13,209
WESTERN	44	97.8	8.3	0.10	0.58	0.8	12,770
TOTAL U. S.	455	93.8	7.5	0.85	2.00	3.0	13,530

SUMMARY OF THE PHYSICAL DESULFURIZATION POTENTIAL OF COALS BY REGION
Figure 2.1.6

- PARTIAL PHYSICAL CLEANING FOR PYRITE REMOVAL
  - EASILY CLEANED COALS
  - MODERATE EMISSION STANDARDS
- TOTAL PHYSICAL CLEANING
  - SINGLE SULFUR LEVEL PRODUCT
  - MULTIPLE SULFUR LEVEL PRODUCTS
- COMBINATIONS OF PHYSICAL COAL CLEANING AND FGD
- COMBINATIONS OF PHYSICAL AND CHEMICAL COAL CLEANING

EMISSION CONTROL STRATEGIES FOR SO_2 EMISSION CONTROL
Figure 2.1.8

TECHNICAL & REGULATORY UNCERTAINTIES

- PERFORMANCE OF EQUIPMENT IN SULFUR REMOVAL
- PROCESS CONTROL
- EFFECTS OF CLEANED COAL ON:
  - BOILER PERFORMANCE
  - ESP PERFORMANCE
  - RESIDUE DISPOSAL REQUIREMENTS
- POSSIBLE NEW REGULATORY ACTIONS

BARRIERS TO IMPLEMENTATION OF COAL CLEANING FOR SO_2 EMISSION CONTROL

Figure 2.1.9

INSTITUTIONAL AND ECONOMIC

- UNCLEAR COST DIFFERENTIAL FOR SULFUR CLEANED COAL
- NON-UTILITY OWNERSHIP OF COAL RESOURCES
- TOTAL COSTS RELATIVE TO OTHER SO_2 CONTROL METHODS
  - EXISTING INVESTMENTS AND CONTRACTS
  - COSTS OF NEW MINES AND FACILITIES
  - COST AND SCARCITY OF CAPITAL

BARRIERS TO IMPLEMENTATION OF COAL CLEANING FOR SO_2 EMISSION CONTROL

(Continued)

Figure 2.1.10

CURRENT STATUS

- ACCEPTANCE OF COAL CLEANING FOR SO_2 CONTROL
  - -UTILITIES
  - -COAL INDUSTRY
- AWARENESS BY LEGISLATORS AND REGULATORY AGENCIES
- ACCELERATION OF TECHNOLOGY DEVELOPMENT

CONCLUSION: STATUS OF COAL CLEANING TECHNOLOGY

Figure 2.1.11

METHODS FOR ACCELERATING IMPLEMENTATION

- POSITIVE LEGISLATIVE AND REGULATORY ACTIONS
- TECHNOLOGY DEVELOPMENT
  - IMPROVE PROCESS CONTROLS
  - OBTAIN ADDITIONAL CLEANING EQUIPMENT PERFORMANCE DATA
  - REFINE CLEANING AND POLLUTION CONTROL COSTS
  - OBTAIN ADDITIONAL RESERVE DATA

CONCLUSION: METHODS FOR ACCELERATING IMPLEMENTATION OF COAL CLEANING TECHNOLOGY

Figure 2.1.12

PHYSICAL COAL CLEANING CONTRACT RESEARCH BY THE U.S. BUREAU OF MINES

P. S. Jacobsen
A. W. Deurbrouck

INTRODUCTION

Physical coal cleaning research as typically performed by the U.S. Bureau of Mines has involved mainly in-house evaluations. Very little contract research has been funded. This trend is now being altered as a result of increased national attention being paid to coal and its preparation to meet ever-expanding demands for energy consistent with legislated environmental restraints. The Bureau of Mines and EPA under an interagency agreement have responded to meet this energy demand with increased programs in both in-house and contract research on physical coal cleaning. Current and proposed contract research is discussed in this paper.

SPECIFIC STUDIES

Contracts in the following specific areas are now current:

- Surface phenomena in the dewatering of coal.
- Control of black water in coal preparation plant recycle and discharge.
- High gradient magnetic separation (HGMS).
- Adsorption-desorption reactions in the desulfurization of coal by a pyrite flotation technique.

Surface Phenomena in the Dewatering of Coal

USBM/EPA Contract No.: G0155137
Duration: 36 months
Starting date: July 1, 1975
Total dollar value: $75,779
Syracuse University

During this investigation, experiments will be conducted to characterize the dewatering of fine-size coal, to estimate the effect of an electric field on the dewatering process, to determine the influence that slurry pH has on dewatering, and to assess the influence of selected chemical additives on moisture retained in filter cakes.

Control of Black Water in Coal Preparation Plant Recycle and Discharge

USBM/EPA Contract No.: G0155158
Starting date: July 1, 1975
Duration: 24 months
Total dollar value: $55,366
Pennsylvania State University

Under this grant, a laboratory investigation of the flocculation process is being carried out in the treatment of black water from coal preparation plants. In this investigation, a quantitative evaluation will be made of the interrelation of coagulation rate, settling rate, and sludge volume to establish a technique for producing as dense a sludge as possible from a thickener operating at the highest possible rate. Further, the results of studies on the coagulation of heterogeneous systems will be used to develop mathematical models to simulate the coagulation of particles in practical systems.

High Gradient Magnetic Separation (HGMS)

USBM/EPA Contract No.: H0366008
Starting date: March 1, 1976
Duration: 12 months
Total dollar value: $85,020
General Electric Company

USBM/EPA Contract No.: H0366009
Starting date: March 19, 1976
Duration: 13 months
Total dollar value: $94,690
Massachusetts Institute of Technology

USBM-National Science Foundation
Starting date: March 1, 1976
Duration: 15 months
USBM funding: $25,000 Total: $132,100
Indiana University Foundation

General Electric Company, in conjunction with The Massachusetts Institute of Technology (MIT) and Eastern Associated Coal (EAC), is attempting to establish the technical feasibility of removing a substantial fraction of the inorganic sulfur from dry coal powders at commercially significant processing rates. Reduction of sulfur by HGMS could permit the direct combustion of large coal reserves east of the Mississippi River, which have a high percentage of pyritic sulfur but are low in organic sulfur. In tests to date, significant reductions in pyritic sulfur, as well as ash, were achieved. The data are presented in Figures 2.2.1 and 2.2.2.

Under another Bureau of Mines-EPA contract, researchers at the Massachusetts Institute of Technology are studying the application of HGMS to the recovery of fine-size magnetite from dense-medium circuits in coal preparation plants.

In addition, the Bureau of Mines is partially funding HGMS investigations being conducted at the Indiana University Foundation. The general objective of this project is to transfer the new high gradient magnetic separation technology to the beneficiation and concentration of coal and metallic ores (ferrous and nonferrous), and make possible the recovery of coal and ores not currently economically viable.

Adsorption-Desorption Reactions in the Desulfurization of Coal by a Pyrite Flotation Technique

USBM/EPA Contract No.: H0155169
Starting date: July 1, 1975
Duration: 24 months
Total dollar value: $102,252
University of Utah

Recent studies by the Bureau have demonstrated that a promising new two-stage pyrite flotation technique can reduce the pyritic sulfur content of fine coal. Several aspects of this proposed flotation separation require detailed study at a fundamental level and constitute the basis for this investigation. Specific details of the proposed research work under this contract include:

- Identify and characterize the hydrophilic polymeric second-stage coal depressants.
- Determine the important operating variables which control the adsorption-desorption reactions, and relate these results to the flotation response of the mineral constituents.
- Establish procedures, as necessary, to allow for subsequent coal flotation and plant water recycle without deleterious effects due to residual reagent concentrations.

Studies of colloidal depressant adsorption by one of the coals have shown that starch (dextrin) has a high adsorption potential, and that effective coal depression can be achieved by relatively low (0.1 mg/1) concentrations (Figure 2.2.3) which correspond to less than monolayer coverage. The flotation response of coal-pyrite in the presence of xanthate, however, is not significantly affected by dextrin additions of less than 60 mg/1 (Figure 2.2.4).

GENERAL STUDIES

Contracts in the following more general areas are now current or are being negotiated:

- Lignite upgrading.
- Characteristics and removal of pyritic sulfur from selected U.S. coals.
- Computer simulation of coal preparation plants.
- Engineering/economic analysis of coal preparation with SO_2 cleanup processes for keeping higher sulfur coals in the energy market.

Lignite Upgrading — USBM Contracts Under Negotiation.

The lignite deposits of North Dakota and Montana represent one of the largest fossil fuel reserves of the United States, totaling more than 23 billion tons of recoverable reserves. The utilization of this fuel has been limited by its high inherent moisture content, tendency toward spontaneous combustion, and its often high sodium content. The goal of the Bureau of Mines program to upgrade lignite will be to produce a final product that will contain 10 percent moisture and 0.3 percent sodium. The final product will be a pellet of sufficient mechanical strength to resist breakage during shipment and storage and will be resistant to spontaneous combustion.

The reduction of the sodium content of lignite and the pelletization and heat drying of the lignite pellets are the major unit operations in a proposed 5-ton-per-hour pilot plant for upgrading lignite. Two contracts are being negotiated, one to develop a practical continuous process for removing sodium from lignite by ion exchange, and another to demonstrate the pelletization of lignite and the subsequent drying of the pellets to a moisture content of 10 percent or less.

Characteristics and Removal of Pyritic Sulfur From Selected U.S. Coals

USBM/EPA Interagency Agreement
Starting date: July 1, 1965
Duration: Continuing
Total dollar value per fiscal year: $150,000

In 1965, the Federal Government funded a continuing study by the Bureau of Mines; and in 1967, a similar study for 2 years' duration by the Commercial Testing and Engineering Company to determine the forms of sulfur in the major sources of utility steam coals, and the washabilities of these coals. RI 8118 entitled "Sulfur Reduction Potential of U.S. Coals" has been published; the data in this report were compiled from the work done in these two studies, thus covering work performed from 1965 to mid-1974.

This report presents the results of a washability study of 455 raw coal channel samples with special emphasis on sulfur reduction. The information generated by this study is necessary to assess the impact physical desulfurization of coal might have on the level of sulfur oxide emissions from stationary combustion sources. This study is being continued by the Bureau of Mines under the Interagency Agreement.

Figure 2.2.5 shows that significant reductions of impurities can be obtained, especially ash and pyritic sulfur contents, by crushing and gravimetric separation.

Figure 2.2.6 shows that only 14 percent of raw coal samples as mined could meet the new source SO_2 emission standard of 1.2 pounds SO_2/MM Btu. Twenty-four percent of the samples would meet the standard at a 90-percent Btu recovery when crushed to 1½-inch top size, while 32 percent would meet the standard at a Btu recovery of 50 percent when crushed to 14-mesh top size.

The composite data (Figure 2.2.7) show that if all the coals were upgraded at a specific gravity of 1.60, the analyses of the clean coal products of the various regions would range on the average from 5.1 to 8.3 percent ash, 0.10 to 1.80 percent pyritic sulfur, 0.56 to 3.59 percent total sulfur, and 12,779 to 14,264 Btu per pound; and would produce 0.95 to 5.5 pounds of SO_2/MM Btu at Btu recoveries ranging from 91.7 to 97.6 percent. The corresponding SO_2 removal efficiencies required for a stack gas scrubbing system to bring these coals into compliance with the Federal sulfur emission regulations of 1.2 pounds SO_2/MM Btu would range from zero to 78 percent.

Computer Simulation of Coal Preparation Plants

USBM/EPA Interagency Agreement
USBM Contract No.: G0155030
Starting date (Phase II): December 1, 1975
Duration: 21 months
Total dollar value (Phase II): $93,657
University of Pittsburgh

To assist in the prediction of full-scale coal preparation plant operation, a computer simulation program is being developed under contract with the University of Pittsburgh. The standard prediction of product quality is included (such as ash, sulfur, Btu, and yield), calculated on the basis of extensive equipment performance distribution data collected by the Bureau of Mines. Several other features, though, are more novel. This includes the mathematical modeling of the rotary breaker, other crushers, screens (both wet and dry), centrifugal and thermal dewatering equipment, and hydraulic and static thickeners. The overall capability of the computer program is such that a build-your-own preparation plant can be simulated. In addition, the capital and operating costs for that particular plant will be available from an extensive economic-evaluation subroutine. This complete simulation program will thus enable rational choices to be made of alternate circuits for ash and sulfur reduction based on reliable engineering data and overall capital operating economics. A more complete summary of this computer simulation study is being presented at the 14th International Symposium on The Application of Computer Methods in the Mineral Industries, October 4-8, 1976, at The Pennsylvania State University.

Engineering/Economic Analysis of Coal Preparation With SO_2 Cleanup Processes for Keeping Higher Sulfur Coals in the Energy Market

USBM/EPA Contract No.: J0155171
Starting date: June 30, 1975
Duration: November 30, 1976
Total dollar value: $79,534
Hoffman-Muntner Corporation

An interesting study has just been completed for the Bureau of Mines by the Hoffman-Muntner Corporation entitled "Engineering/Economic Analysis of Coal Preparation With SO_2 Cleanup Processes for Keeping Higher Sulfur Coals in the Energy Market." This study was done to evaluate the economic potential of coal preparation when combined with stack gas scrubbing. Generally speaking, of the various methods for reducing the sulfur content of coals, the physical removal of pyritic sulfur is the lowest cost and most widely applied technology. However, a number of those coals currently being mined and utilized cannot, by physical upgrading alone, meet the new source sulfur emission standard of 1.2 pounds of SO_2 per million Btu. The concept of physical coal cleaning combined with flue gas desulfurization is not new. For some time there have been discussions, speculations, and some preliminary assessments addressing the possible benefits of physical coal desulfurization followed by flue gas desulfurization.

The Hoffman-Muntner study is an in-depth analytical assessment of a number of theoretical case studies. In these studies, actual coal use areas, coal source areas, and the most probable coalbed source are defined. An economic evaluation is then made of the cost of a new utility plant exclusively removing SO_2 by stack gas scrubbing down to the new source emission standard. This is followed by a similar evaluation of the combined use of physical coal cleaning plus stack gas scrubbing to attain the same sulfur emission level.

The complete results of this study will be presented at the National Coal Association/Bituminous Coal Research Coal Conference in Expo 3, October 19-21, in Louisville, Kentucky.

U.S. Bureau of Mines Coal Preparation Process Development Facility

USBM/EPA Contract: J0366002
Starting date: April 5, 1976
Duration: 9 months
Total dollar value: $412,000
Birtley Engineering Corporation — Professional Services for Design and Engineering Data for the Coal Preparation Process Facility, Equipment, and Structural Support.

USBM/EPA Contract No.: J0366050
Starting date: July 15, 1976
Duration: 8 months
Total dollar value: $206,665
Williams/Trebilcock/Whitehead (Architect-Engineering Services)

The coal preparation research of the U.S. Bureau of Mines is widely recognized for its depth and general applicability to the needs of industry. Nevertheless, in the United States there is no government operated fully integrated process-development-type facility for testing a new coal washing technique, flowscheme, or piece of equipment.

With the implementation of a central coal preparation process development facility operated by the Bureau at the Bruceton, Pa., location, many of the past problems of introducing new technology to the industry would be alleviated. Unbiased engineering data could be readily scaled up to full-size commercial coal preparation plant operation. Moreoever, the expense of evaluating processes that prove to be of limited value to the industry would be greatly reduced.

The pilot plant section of the proposed facility will have a nominal capacity of 10 to 25 tons per hour of raw coal depending on the flowscheme used; process flexibility will be a prime design requisite of this pilot plant.

The facility will contain also an equipment and process development area smaller in scale than the pilot plant to initiate work on research projects before they are taken into the pilot plant section for scale-up to commercial realization. Supporting bench-scale and analytical laboratories and offices for engineering support personnel will complete the proposed Coal Preparation Process Development Facility, as shown in an artist's rendering in Figure 2.2.8.

SUMMARY

This brief report of U.S. Bureau of Mines-EPA contract research shows the wide spectrum of interest these agencies have in physical coal preparation. As increasing attention is given by the Nation to energy-related problems, the Bureau and EPA will keep pace with expanding programs in contract research of both physical and chemical coal preparation.

MAGNETIC FIELD INTENSITY (kilo oersteds)	VELOCITY (cm/sec)	REDUCTION IN SULFUR (Percent)
10.69	2.80	11.1
21.38	2.80	42.5
42.75	2.80	48.8
64.13	2.80	56.8
85.5	2.80	44.0
21.38	1.51	51.3
21.38	3.26	48.7
21.38	4.55	18.8
21.38	5.86	21.4
21.38	9.80	7.1
0	1.74	9.2
0	2.98	0

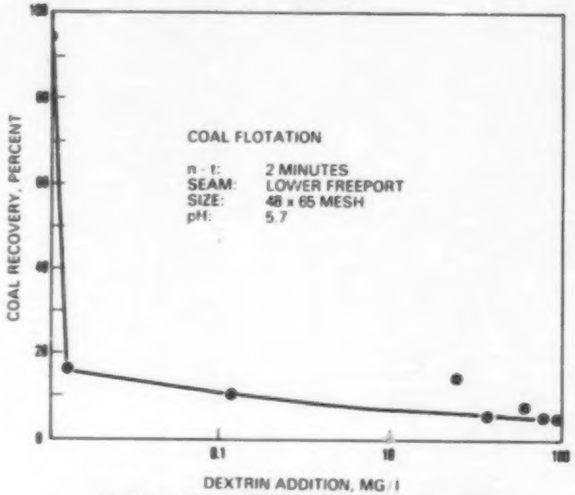
REDUCTION IN TOTAL SULFUR OF EASTERN COALS (48 mesh by O) USING HIGH GRADIENT MAGNETIC SEPARATION

Figure 2.2.1

MAGNETIC FIELD INTENSITY (kilo oersteds)	VELOCITY (cm/sec)	REDUCTION IN ASH (percent)
10.69	2.80	32.6
21.38	2.80	43.1
42.75	2.80	48.6
64.13	2.8C	55.2
85.5	2.80	47.9
21.38	1.51	44.7
21.38	3.26	45.6
21.38	4.55	16.7
21.38	5.86	14.7
21.38	9.80	8.5
0	1.74	7.0
0	2.98	15.3

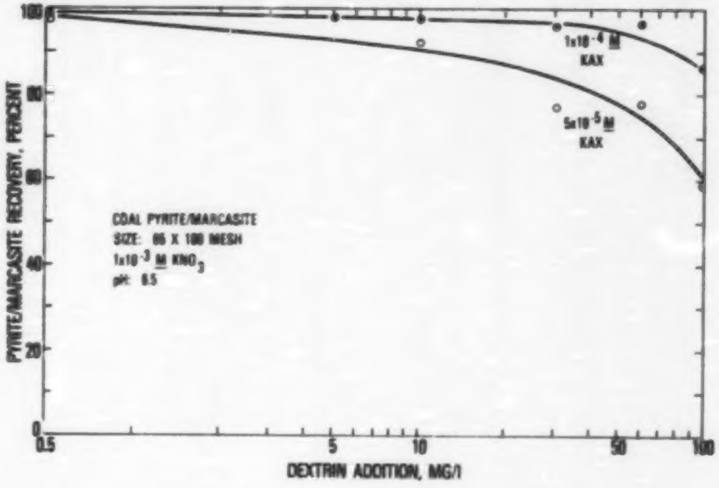
REDUCTION IN ASH OF EASTERN COALS (48 mesh by O) USING HIGH GRADIENT MAGNETIC SEPARATION

Figure 2.2.2



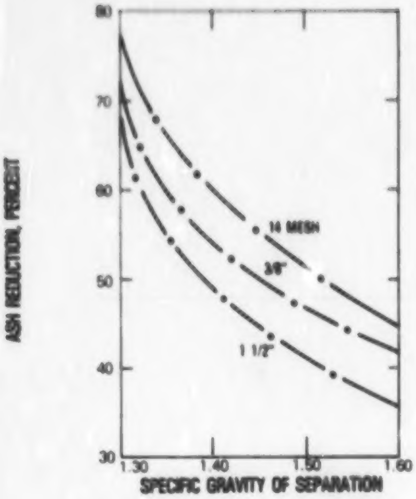
COAL FLOATATION RECOVERY IN THE ABSENCE OF ABRASION

Figure 2.2.3



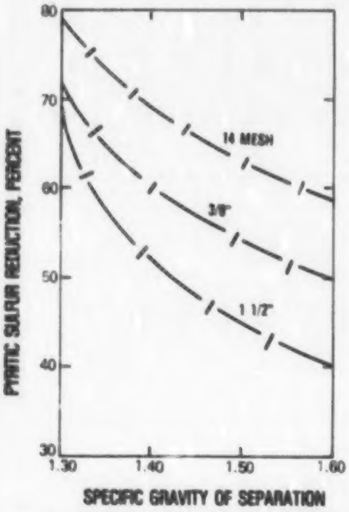
EFFECT OF DEXTRIN ADDITION ON COAL-PYRITE FLOTATION WITH POTASSIUM AMYL XANTHATE (KAX) AS COLLECTOR.

Figure 2.2.4



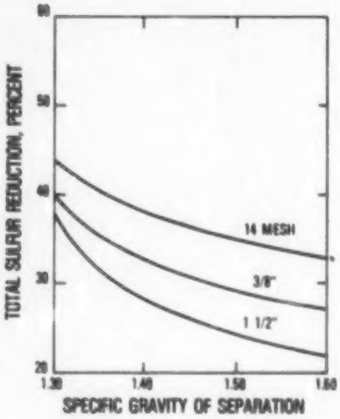
ASH REDUCTION FOR TOTAL U.S. (455 SAMPLES)

Figure 2.2.5a



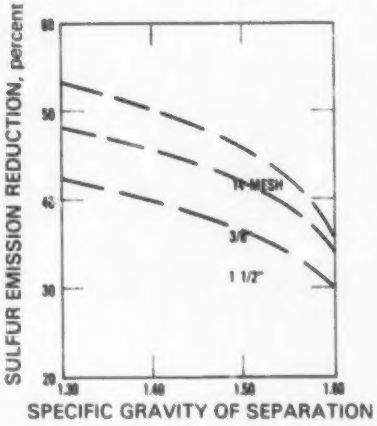
PYRITIC SULFUR REDUCTION FOR TOTAL U.S. (455 SAMPLES)

Figure 2.2.5b



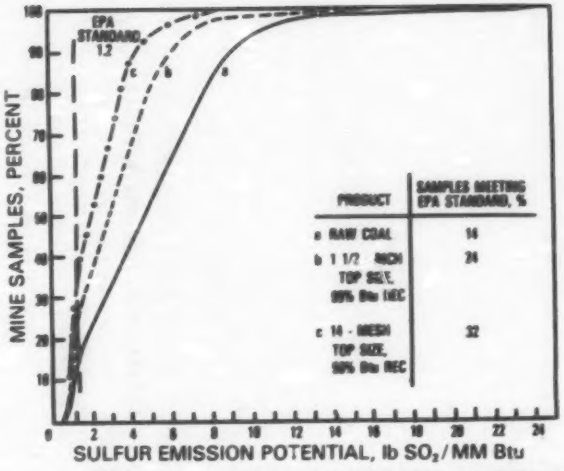
SULFUR REDUCTION FOR TOTAL U.S. (455 SAMPLES)

Figure 2.2.5c



SULFUR EMISSION REDUCTION FOR TOTAL U.S. (455 SAMPLES)

Figure 2.2.5d



TOTAL U.S. COAL SAMPLES MEETING EPA SO_2 STANDARDS (455 SAMPLES)

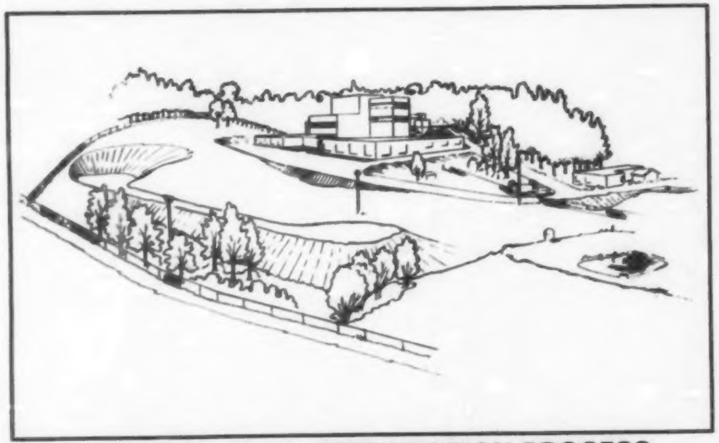
Figure 2.2.6

REGION	*RESULT OF CLEANING At 1.60 SPECIFIC GRAVITY ($lb\ SO_2/MM\ Btu$)*	*FGD EFFICIENCY REQUIRED TO MEET NEW SOURCE PERFORMANCE STANDARDS*
NORTHERN APPALACHIAN	2.7	56
SOUTHERN APPALACHIAN	1.3	8
ALABAMA	1.7	29
EASTERN MIDWEST	4.2	71
WESTERN MIDWEST	5.5	78
WESTERN	0.9	NONE
TOTAL UNITED STATES	3.0	60

COALS CRUSHED TO PASS 3/8 INCH TOP SIZE

COMBINATION COAL PREPARATION AND FLUE GAS DESULFURIZATION (FGD) TREATMENT TO MEET NEW SOURCE PERFORMANCE STANDARDS FOR STEAM GENERATORS

Figure 2.2.7



U.S.B.M. COAL PREPARATION PROCESS DEVELOPMENT FACILITY, BRUCETON, PA. (ARTIST CONCEPTION AS OF 14 MAY 76)

Figure 2.2.8

REVIEW AND STATUS OF THE TRW/MEYERS PROCESS

R. A. Meyers
L. J. Van Nice
M. J. Santy

INTRODUCTION

Coal can be desulfurized prior to combustion using the Meyers Process(1,2) to meet governmental requirements for sulfur oxide emissions.

The physical form of the coal remains unchanged, only sulfur and some inorganic materials are removed. The process removes up to 80 percent of the total sulfur content of coal through chemical leaching of 90 to 95 percent of the pyritic sulfur contained in the coal matrix with aqueous ferric sulfate solution at temperatures of 90° to 130°C. The ferric sulfate content of the leach solution is regenerated at similar temperatures using air or oxygen; and elemental sulfur and iron sulfates are recovered as reaction products, or alternatively, gypsum can replace a portion of the iron sulfates as a product.

The process consists of several steps including crushing, chemical treating, sulfur removal, and solution regeneration (Figure 2.3.1). While the process is new, the unit operations are based on various existing technologies such as: processes for the heap leaching of copper (operation 1), (Figure 2.3.3), regeneration of steel mill waste pickle liquor (operation 3), and the recovery of elemental sulfur from volcanic ash (operation 2). The chemistry of the process is represented by the treating step (Equation 1) and the solution regeneration (Equation 2):

$$FeS_2 + 4.6\,Fe_2(SO_4)_3 + 4.8\,H_2O \rightarrow 10.2\,FeSO_4 + 4.8\,H_2SO_4 + 0.8\,S \qquad (1)$$

$$2.4\,O_2 + 9.6\,FeSO_4 + 4.8\,H_2SO_4 \rightarrow 4.8\,Fe_2(SO_4)_3 + 4.8\,H_2O \qquad (2)$$

A set of products which can be obtained from a 440 tph (6,400 hrs/yr operation) Meyers Process plant removing 1.0 percent by weight pyritic sulfur from coal is shown below:

Product	Tons/year
Elemental Sulfur	11254
$CaSO_4 \bullet 2H_2O$	15137
$FeOH\,SO_4$	74509

The process applies primarily to coals rich in pyritic sulfur rather than those with mainly organic sulfur. Such coal is found in the Appalachian region of the United States which now supplies 60 percent of the current U.S. production. This production can be lowered to sulfur contents of 0.6 to 0.9 percent for an estimated one-third of the production, at which level the emission requirements for new power plants can be met(3). Most remaining Appalachian coal and Eastern Interior Basin coal can meet state and local standards for existing power plants after treatment by the Meyers Process(4).

TEST PLANT

The Process is under development for the Environmental Protection Agency. Because of the success of extensive laboratory and bench-scale testing (over 200 separate material balanced leach and regeneration runs on over 30 different coals), the process is now in scale-up. A Reactor Test Unit (RTU) sized to process up to 8 tons per day of coal is being built, under the sponsorship of EPA at TRW's Capistrano Test Site (Figure 2.3.11). The RTU facility will be capable of on-line evaluation of the following critical process operations:

- Leaching of pyritic sulfur from 10 to 100 mesh top-size coal.

- Regeneration of ferric sulfate both separately, for processing larger top-size coal or low pyrite coal, and in a single vessel with the leaching step for processing of suspendable coal.
- Filtration of leach solution from reacted coal.
- Washing of residual iron sulfate from the coal.

Iron sulfate crystallization, elemental sulfur recovery, and coal-drying unit operation will be evaluated in an off-line mode. Coarse coal processing (¼- to ⅜-inch top-size) has been very promising in laboratory tests[5]. If this approach proves out in bench-scale evaluation, coarse coal leaching units may be added to the RTU.

Processing fine coal allows the highest rate of pyritic sulfur removal, while processing coarse coal, although slower, allows lower cost coal dewatering units and the direct shipping of desulfurized coal product without need for pelletizing.

ENGINEERING DESIGN AND COST ESTIMATES

Conceptual design or cost estimates of full-scale plants have recently been prepared by a number of organizations including TRW(5), Dow Chemical USA(6), Exxon(7) and EPRI - U. of Michigan(8). They show that the process is economically competitive with projected costs for flue gas scrubbing, particularly for small installations or the average coal-fired electric utility where power generation load factors are less than 90 percent.

Some of the process variations which have been tested and engineered include the following:

- Leaching and regeneration temperatures of 90° to 130°C.
- Leaching and regeneration in the same or separate vessels.
- Removal of generated elemental sulfur by vaporization or solvent extraction.
- Air vs oxygen for regeneration.
- Feed coal top-sizes of ¼-inch, 14-mesh, 100-mesh and near 200-mesh.
- Slurry solids content from 20 to 33 percent.
- Oxygen partial pressures of 1 to 8 atm.
- Combinations of the process with coal cleaning plants.
- Collocation with the power plant at a mine or at a separate site.

A processing cost range (investor financed) of $7 - $14/ton of coal is reported by Dow(6) for treatment of fine coal, with a thermal efficiency of 90 percent from run-of-mine coal crushing to desulfurized and crushed product coal. A processing cost range (utility financed) of $6 to $10/ton is reported by TRW(5) for treatment of fine coal and $3 to $6 for treatment of coarse ¼- or ⅜-inch top-size coal. Coal yield, on a Btu basis, is 94 percent for fine coal and 90 to 95 percent for coarse coal. Overall process thermal efficiency based on an Exxon developed flowsheet was recently calculated at 92.1 percent(7).

A TRW developed flow diagram for treatment of fine coal (14-mesh top-size) by the Meyers Process is shown in Figure 2.3.14. In this design, leaching and regeneration is accomplished in the same vessel at a temperature of 120°C and oxygen partial pressure of 1 to 5 atm. Approximately 85 percent of the pyrite is reacted in the first vessel. Reaction is completed to the 90 to 95 percent level in the second reactor. The coal is then washed free of residual iron sulfate and conveyed to a dryer where generated elemental sulfur is vaporized and the coal is dried. The products of this particular design are those described above. The capital cost for a coal desulfurization plant to provide low sulfur utility coal, which was developed from a detailed flow diagram and equipment list, is $100/KW power plant name plate capacity operating at baseload(5). This is for removal of 3 percent sulfur from raw run-of-mine coal. For lower pyritic sulfur coals, cleaned coal or less than baseload utilities, the capital cost is diminished. The relative cost of each section is shown in Figure 2.3.13.

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4. Lorenzi, L. Jr., J. S. Land, L. J. Van Nice, E. P. Koutsoukos, and R. A. Meyers. Coal Age, 77 (11) 76, 1972.

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7. McGee, E. M. Evaluation of Pollution Control in Fossil Fuel Conversion Processes, Coal Treatment: Section 1. Meyers Process, Environmental Protection Technology Series, EPA 650-2-74-009K, September 1975.

8. Tek, M. Rasin. Coal Benefication, An Evaluation of Coal Conversion of Processes, PB-234202, 1974.

PROCESS DESCRIPTION

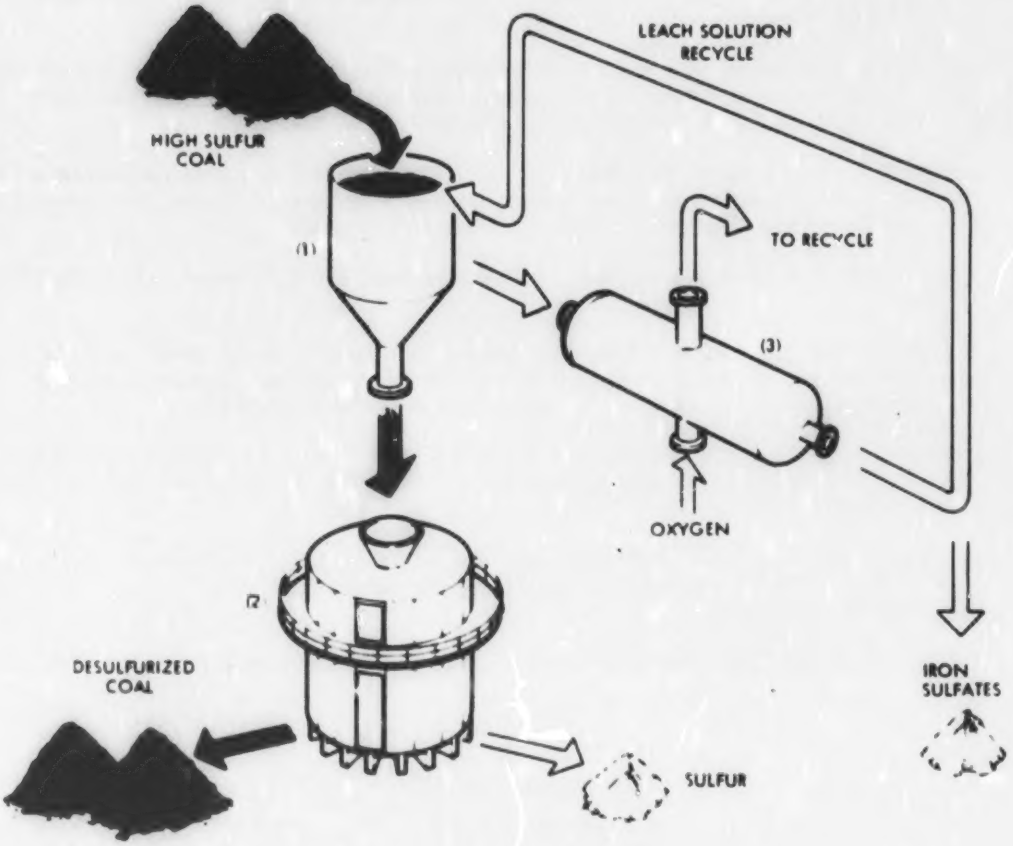
(1) CRUSHED COAL IS TREATED WITH WARM FERRIC SULFATE SOLUTION

$$FeS_2 + 4.6\ Fe_2(SO_4)_3 + 4.8\ H_2O \rightarrow 10.2\ FeSO_4 + 4.8\ H_2SO_4 + 0.8S$$

(2) GENERATED SULFUR IS REMOVED WITH A WARM SOLVENT BATH OR BY VAPORIZATION

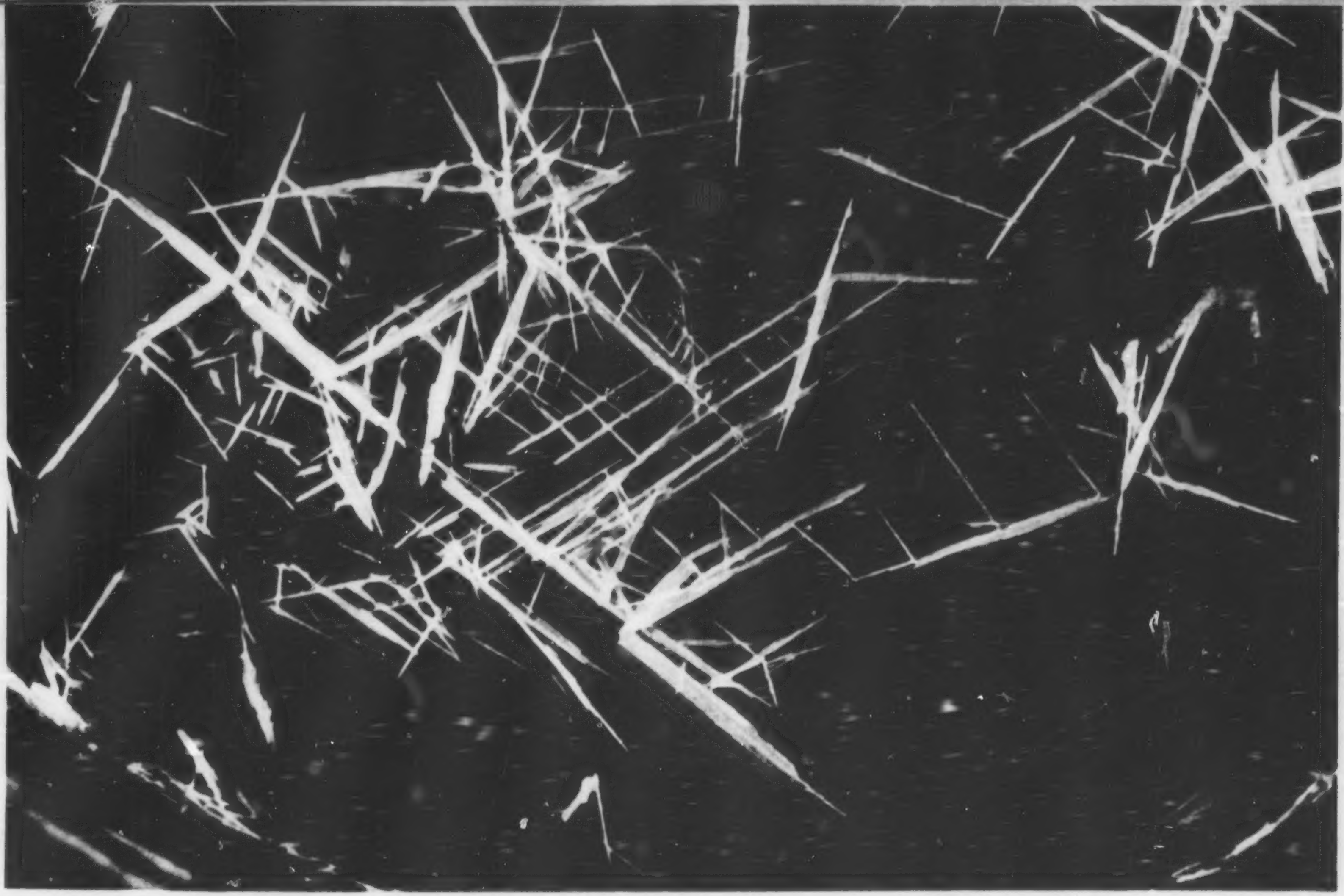
(3) FERRIC SULFATE SOLUTION IS REGENERATED WITH O_2 AND EXCESS FERRIC AND FERROUS SULFATE IS REMOVED

$$9.6\ FeSO_4 + 4.8\ H_2SO_4 + 2.4\ O_2 \rightarrow 4.8\ Fe_2(SO_4)_3 + 4.8\ H_2O$$


LEACH SOLUTION RECYCLE
HIGH SULFUR COAL
(1)
TO RECYCLE
(3)
OXYGEN
(2)
DESULFURIZED COAL
IRON SULFATES
SULFUR

DESCRIPTION OF THE MEYERS PROCESS

Figure 2.3.1



CRYSTALS OF SULFUR PRODUCED BY MEYER'S PROCESS

Figure 2.3.2

$FeS_2 + 4.6\ Fe_2(SO_4)_3 + 4.8\ H_2O \longrightarrow 10.2\ FeSO_4 + 4.8\ H_2SO_4 + 0.8\ S$

$\Delta H = -55$ Kcal/g-mole FeS_2 = -0.10 MM Btu/lb-mole FeS_2 Reacted

CHEMICAL EQUATION AND ENTHALPY ASSOCIATED WITH THE LEACHING STEP

Figure 2.3.3

PYRITE REMOVAL OCCURS IN THE MIXER, LEACH-REGENERATION REACTOR, AND AMBIENT PRESSURE REACTOR. THE REMOVAL RATE IN ALL THREE REACTORS IS GOVERNED BY THE EMPIRICAL LEACHING RATE EXPRESSION

$$r_L = -\frac{dW_p}{dt} = K_L\ W_p^2\ Y^2,$$

WHERE

W_p = WT PERCENT PYRITE IN COAL

Y = FERRIC ION TO TOTAL IRON RATIO IN THE REACTOR REAGENT

K_L = RATE CONSTANT, A FUNCTION OF TEMPERATURE AND COAL TOP-SIZE

KINETICS OF THE LEACHING STEP

Figure 2.3.4

$1.0\ FeSO_4 + 0.5\ H_2SO_4 + 0.25\ O_2 \longrightarrow 0.5\ Fe_2(SO_4)_3 + 0.5\ H_2O$

$\Delta H = -18.6$ Kcal/g-mole $FeSO_4$ = $-.0335$ MM Btu/lb-mole $FeSO_4$

CHEMICAL EQUATION AND ENTHALPY ASSOCIATED WITH THE REGENERATION STEP

Figure 2.3.5

REAGENT REGENERATION IS GOVERNED BY THE RATE EXPRESSION

$$r_R = -\frac{dFe^{+2}}{dt} = K_R\ P_{O_2}\ (Fe^{+2})^2,$$

WHERE

$K_R = A_R \exp(-E_R/RT)$,

P_{O_2} = OXYGEN PARTIAL PRESSURE

Fe^{+2} = FERROUS ION CONCENTRATION IN THE REAGENT SOLUTION

A_R AND E_R ARE CONSTANTS

THE REAGENT REGENERATION RATE OPERATES SIMULTANEOUSLY WITH THE LEACHING RATE IN THE LEACH-REGENERATION REACTOR

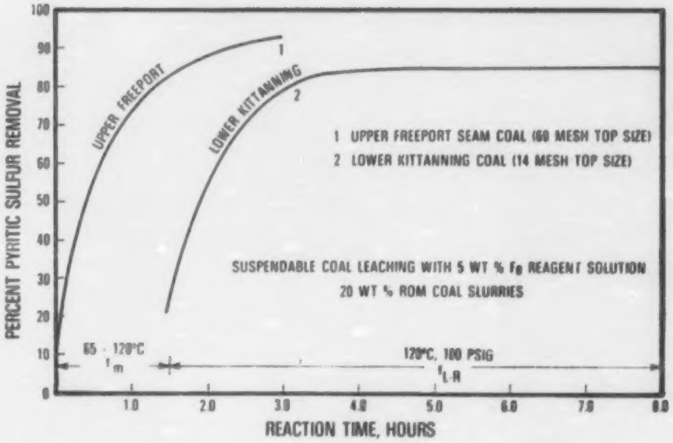
KINETICS OF THE REGENERATION STEP

Figure 2.3.6

OPERATION	TEMP, °C	PYRITE REMOVAL, %	RATIO OF Fe^{+++} TO TOTAL F_e (Y)
1. SLURRY MIXING AND HEATING	20-120	10-20	0.8 → 0.5
2. SIMULTANEOUS LEACHING AND REGENERATION	120	80-90	0.5 → 0.9
3. SETTLING	90	90-95	0.9 → 0.8

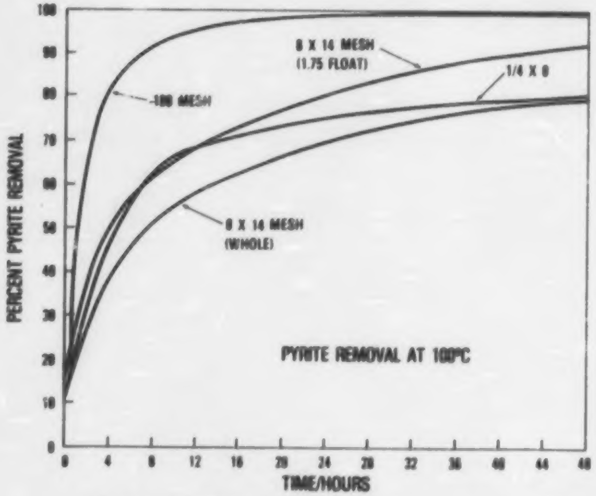
SIMULTANEOUS FERRIC SULFATE LEACH AND REGENERATION-BASED PYRITE REMOVAL PROCESS

Figure 2.3.7



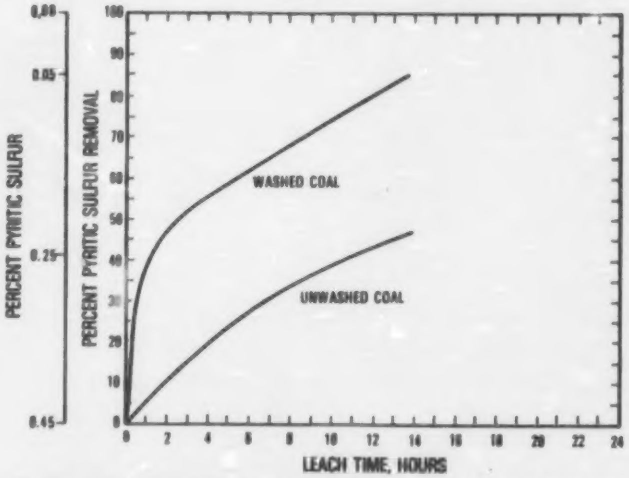
PYRITE LEACHING RATES FROM UPPER FREEPORT AND LOWER KITTANNING MINE COALS

Figure 2.3.8



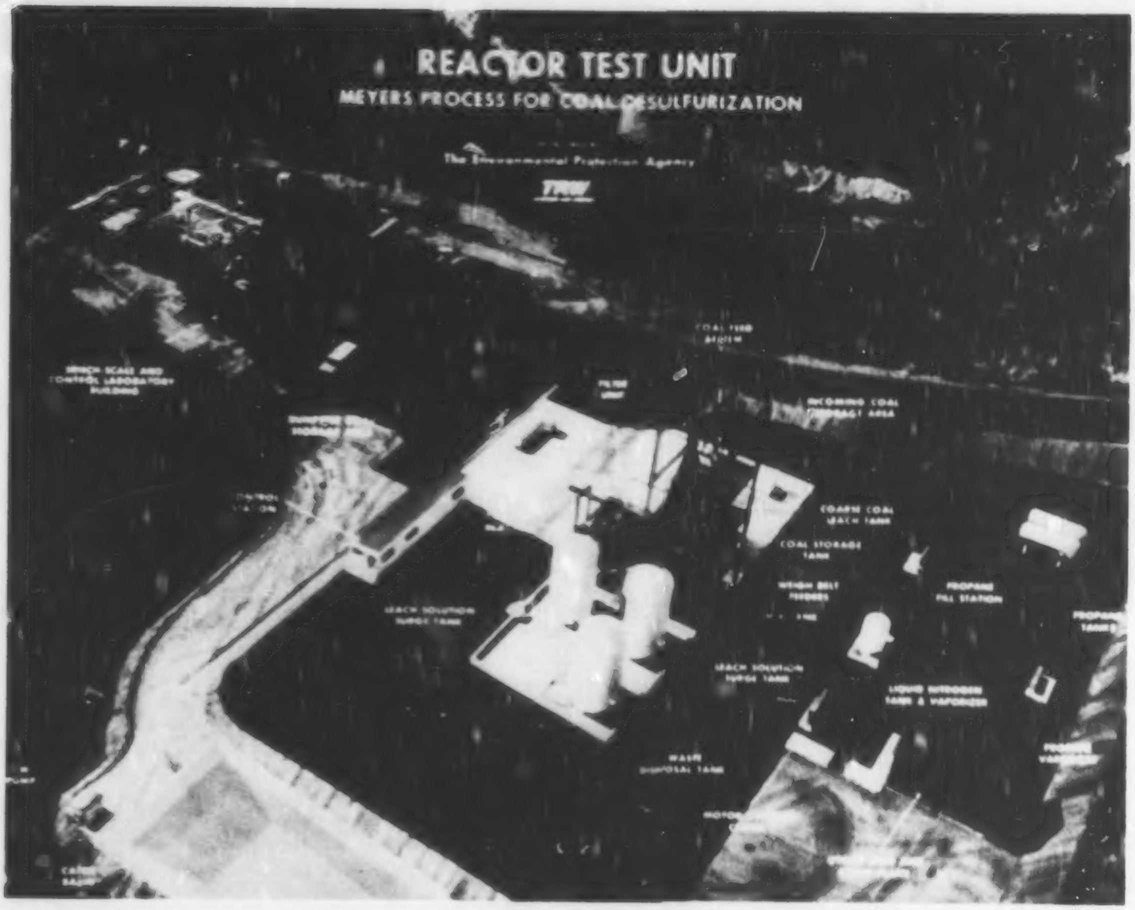
EFFECT OF COAL TOP-SIZE AND CLEANING ON LEACH RATE

Figure 2.3.9



PYRITE REMOVAL AS A FUNCTION OF TIME– WASHED VS UNWASHED COAL AT SAME STARTING PYRITE CONCENTRATION

Figure 2.3.10


REACTOR TEST UNIT
MEYERS PROCESS FOR COAL DESULFURIZATION
The Environmental Protection Agency
TRW
COAL FEED SYSTEM
BENCH SCALE AND CONTROL LABORATORY BUILDING
FILTER UNIT
INCOMING COAL STORAGE AREA
CONTROL STATION
COARSE COAL LEACH TANK
COAL STORAGE TANK
WEIGH BELT FEEDERS
PROPANE FILL STATION
PROPANE TANKS
LEACH SOLUTION SURGE TANK
LEACH SOLUTION SURGE TANK
LIQUID NITROGEN TANK & VAPORIZER
WASTE DISPOSAL TANK
PROPANE VAPORIZER

ARTIST CONCEPTION OF THE REACTOR TEST UNIT (RTU)

Figure 2.3.11

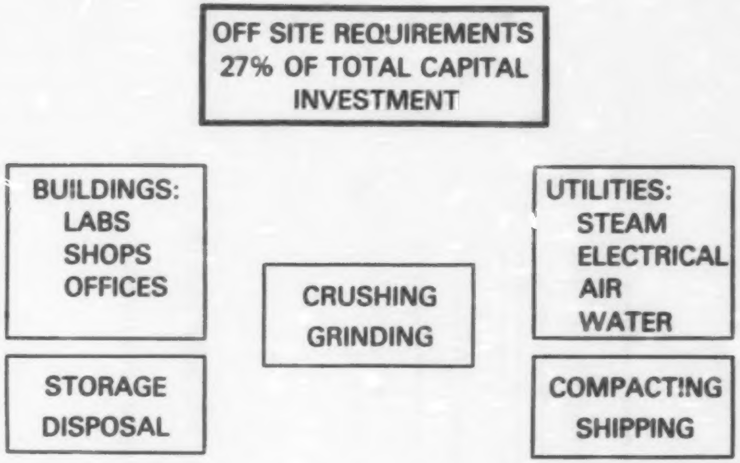
- ONE THIRD (1/3) TON PER HOUR
- CONTINUOUS LEACHING AND REGENERATION
- COAL TOP SIZE RANGE = 8 MESH TO 100 MESH

REACTOR TEST UNIT (RTU) CAPABILITIES

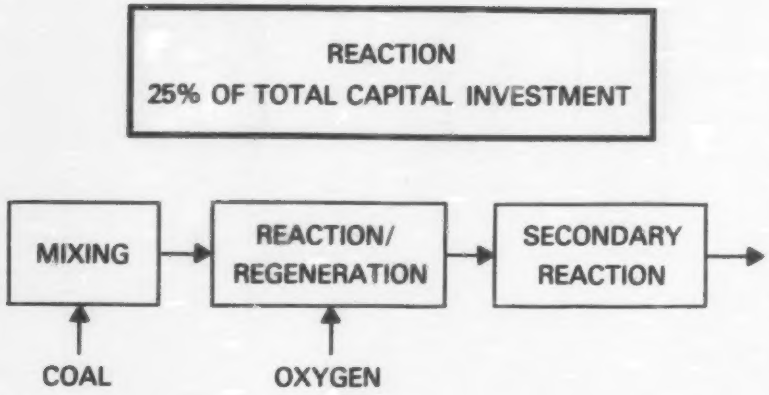
Figure 2.3.12

ITEM	PERCENT OF TOTAL
REACTION	25
WASHING	9
SULFATE REMOVAL	12
SULFUR REMOVAL	7
PROCESS TOTAL	53
OFF SITE REQUIREMENTS	27
CONTINGENCY	20

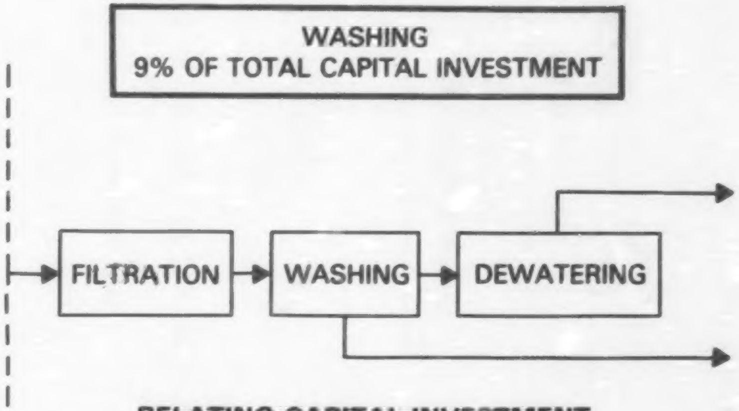
CAPITAL INVESTMENT OVERVIEW FOR THE MEYERS PROCESS
Figure 2.3.13


OFF SITE REQUIREMENTS
27% OF TOTAL CAPITAL INVESTMENT
BUILDINGS:
LABS
SHOPS
OFFICES
CRUSHING
GRINDING
UTILITIES:
STEAM
ELECTRICAL
AIR
WATER
STORAGE
DISPOSAL
COMPACTING
SHIPPING

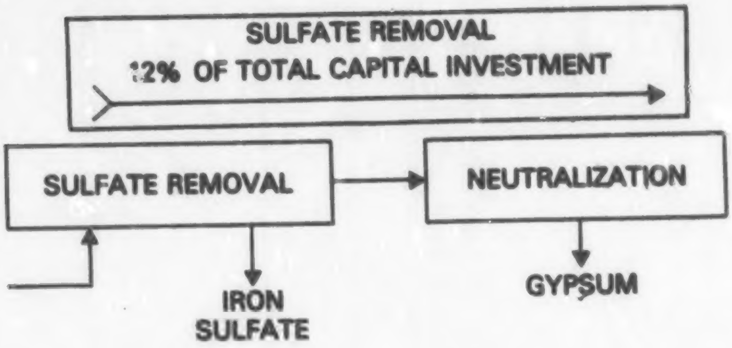
RELATING CAPITAL INVESTMENT TO PROCESS FLOW: OFF SITE REQUIREMENTS
(FINE COAL PROCESSING TRW-MEYERS PROCESS)
Figure 2.3.14 e


REACTION
25% OF TOTAL CAPITAL INVESTMENT
MIXING
REACTION/ REGENERATION
SECONDARY REACTION
COAL
OXYGEN

RELATING CAPITAL INVESTMENT TO PROCESS FLOW: REACTION
(FINE COAL PROCESSING TRW-MEYERS PROCESS)
Figure 2.3.14a


WASHING
9% OF TOTAL CAPITAL INVESTMENT
FILTRATION
WASHING
DEWATERING

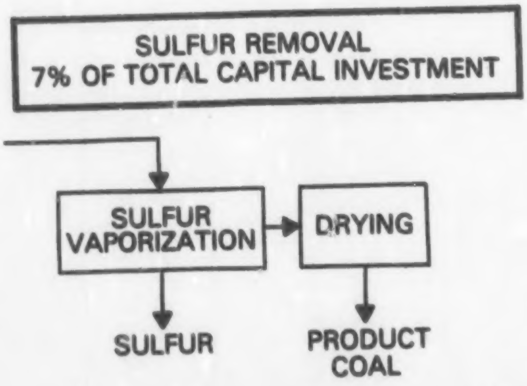
RELATING CAPITAL INVESTMENT TO PROCESS FLOW: WASHING
(FINE COAL PROCESSING TRW-MEYERS PROCESS) CONTINUED
Figure 2.3.14b


SULFATE REMOVAL
12% OF TOTAL CAPITAL INVESTMENT
SULFATE REMOVAL
NEUTRALIZATION
IRON SULFATE
GYPSUM

RELATING CAPITAL INVESTMENT TO PROCESS FLOW: SULFATE REMOVAL

(FINE COAL PROCESSING TRW-MEYERS PROCESS) CONTINUED

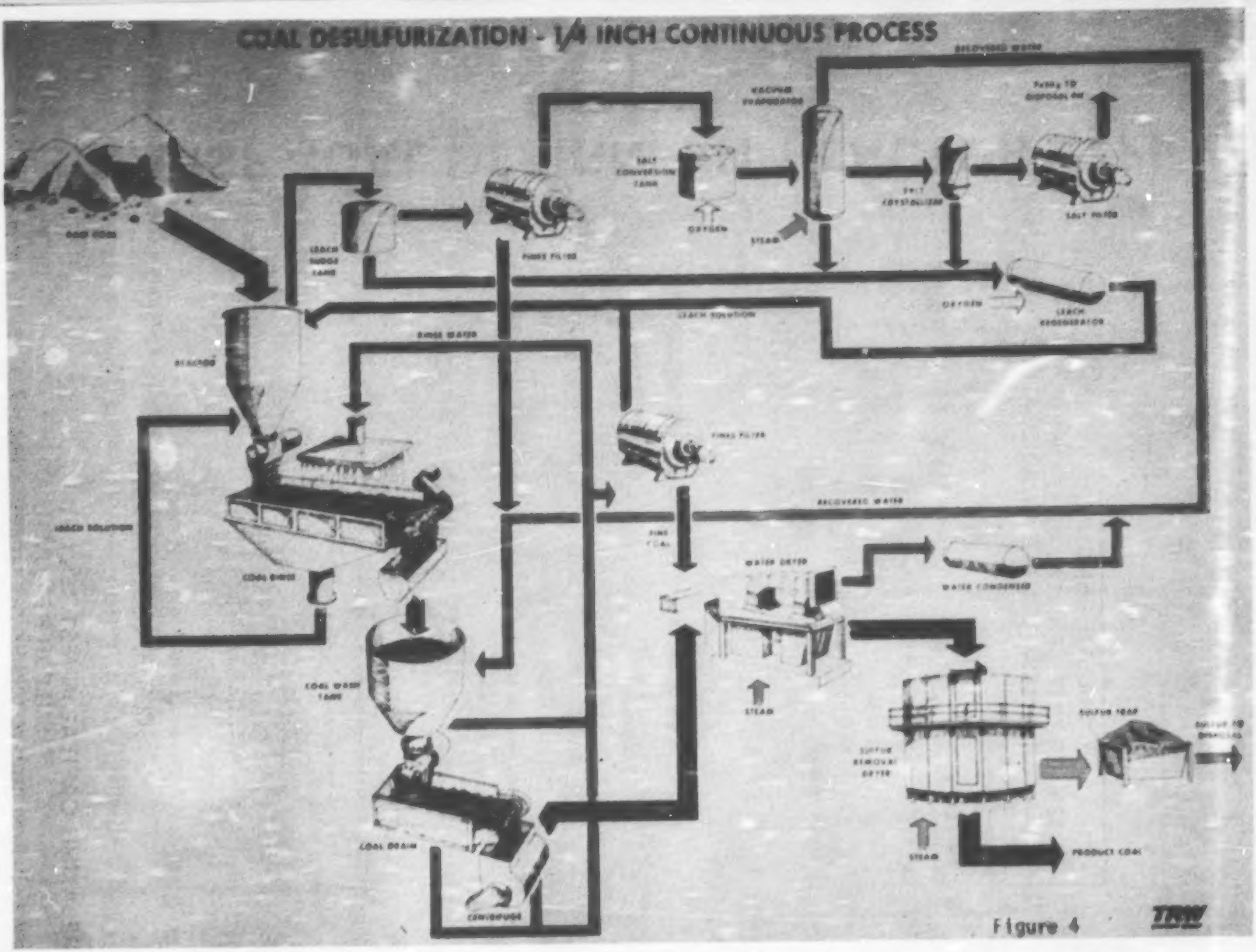
Figure 2.3.14c


SULFUR REMOVAL
7% OF TOTAL CAPITAL INVESTMENT
SULFUR VAPORIZATION
DRYING
SULFUR
PRODUCT COAL

RELATING CAPITAL INVESTMENT TO PROCESS FLOW: SULFUR REMOVAL

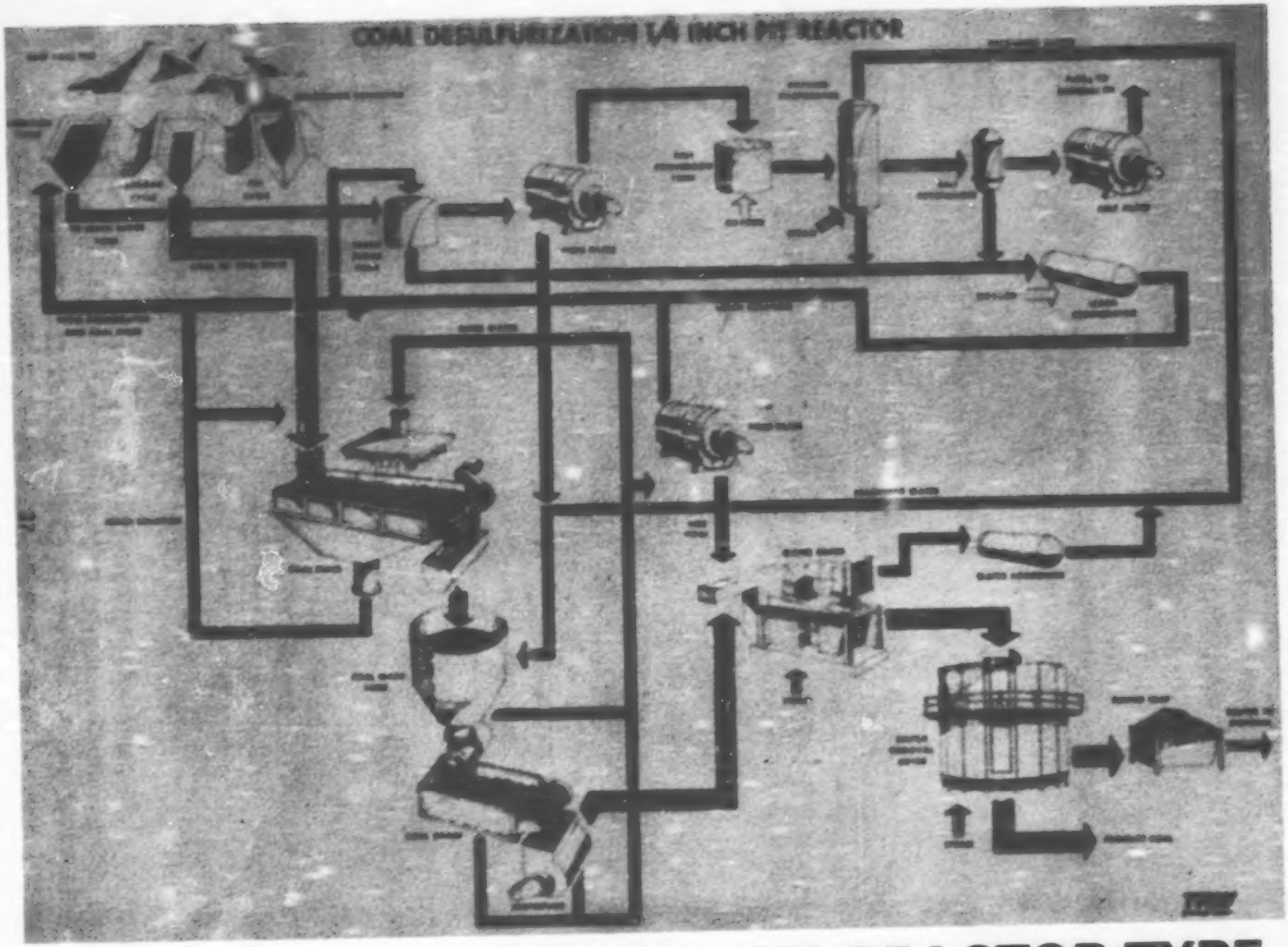
(FINE COAL PROCESSING TRW-MEYERS PROCESS) CONTINUED

Figure 2.3.14d


COAL DESULFURIZATION - 1/4 INCH CONTINUOUS PROCESS
RECOVERED WATER
VACUUM EVAPORATOR
SALT CONVERSION TANK
OXYGEN
STEAM
SALT CRYSTALLIZER
SALT FILTER
LEACH SLUDGE TANK
FINES FILTER
REACTOR
LEACH SOLUTION
OXYGEN
LEACH REGENERATOR
RINSE WATER
FINES FILTER
RECOVERED WATER
FINE COAL
WATER DRYER
WATER CONDENSER
COAL RINSE
COAL WASH TANK
STEAM
SULFUR REMOVAL DRYER
SULFUR TRAP
STEAM
PRODUCT COAL
COAL DRAIN
CENTRIFUGE
Figure 4
TRW

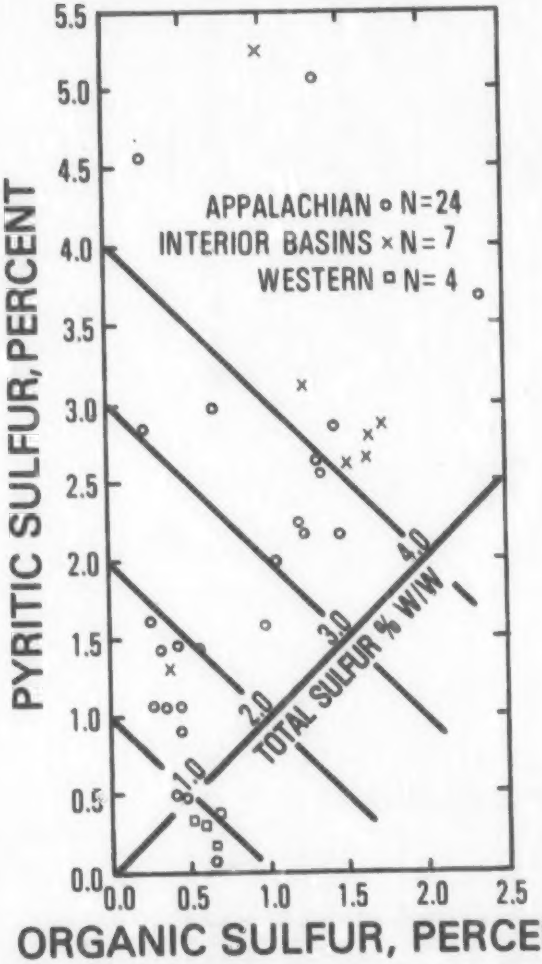
COARSE COAL DESIGN: CONTINUOUS REACTOR TYPE

Figure 2.3.15


COAL DESULFURIZATION 1/4 INCH PIT REACTOR

COARSE COAL DESIGN: PIT REACTOR TYPE

Figure 2.3.16



DISTRIBUTION OF SULFUR FORMS (DRY MOISTURE FREE BASIS) IN RUN-OF-MINE U.S. COALS

Figure 2.3.17

- THROUGH USE OF THE MEYERS PROCESS, SOME 90 BILLION TONS OF APPALACHIAN COAL RESERVES COULD BE PROCESSED TO MEET NEW SOURCE PERFORMANCE STANDARDS (NSPS)
- INCREASED USE OF EASTERN COAL WITHOUT FGD TO MEET NSPS
  - OVERALL ENERGY EFFICIENCY OF THE PROCESS IS 87–91 PERCENT
  - COST ESTIMATES FOR THE PROCESS $8–12/TON
  - ABLE TO REMOVE 90 TO 95 PERCENT OF THE PYRITIC SULFUR

MEYERS APPLICABILITY, ENERGY EFFICIENCY AND COST

Figure 2.3.18

- MAY BE COMBINED WITH PHYSICAL COAL CLEANING AS MEANS OF REDUCING MEYERS PROCESS CAPITAL COSTS
- THE GREATEST POTENTIAL MARKET IS UTILITY, COMMERCIAL, INSTITUTIONAL AND INDUSTRIAL BOILERS

MEYERS STRATEGY AND MARKET POTENTIAL

Figure 2.3.19

EPA HAS FUNDED FOR $5M FOR DESIGN, CONSTRUCTION, AND ONE YEAR TEST

- 8.0 TON/DAY PILOT PLANT
- CONSTRUCTION STARTED IN JULY 1976
- EPA IS SEEKING USER INTEREST DURING ONE YEAR TEST PHASE

MEYERS REACTOR TEST UNIT (RTU) FUNDING

Figure 2.3.20

HYDROTHERMAL COAL DESULFURIZATION WITH COMBUSTION RESULTS*

E. P. Stambaugh
A. Levy, R. D. Giammar
K. C. Sekhar

INTRODUCTION

Coal is the major source of energy for the United States and will continue to be so for many years. However, much of this abundant source of energy contains high concentrations of sulfur, nitrogen, and ash which includes significant quantities of toxic metals. During the combustion of coal, these materials find their way into the environment and thus constitute a health hazard.

Conceptually, the simplest option for reducing the SO_x health hazards associated with coal combustion would be to burn run-of-the-mine low-sulfur coal. However, most of our coal supply has a sulfur content too high to permit direct combustion.

Another alternative is to clean the coal by chemical beneficiation prior to combustion. One potential chemical process for the desulfurization of coal is based on hydrothermal technology. Research results, as discussed in this paper, have confirmed the initial assessment that this approach is a potential means of producing an environmentally acceptable solid fuel from certain coals.

PROCESS DESCRIPTION

As applied to the chemical cleaning of coal, hydrothermal processing entails heating an aqueous slurry of coal and a chemical leachant, at a temperature and for a period of time sufficient to promote the extraction of the impurities from the coal. The basic process as depicted schematically in Figure 2.4.2 comprises 5 major processing operations:

- Coal Preparation
- Hydrothermal Treatment (desulfurization)
- Solids/Liquid Separation
- Fuel Drying
- Leachant Regeneration

Coal preparation may be composed of a simple grinding operation to reduce the raw coal to the desired particle size. On the other hand, this operation may entail two operations — grinding of the coal to the desired particle size followed by a physical beneficiation operation to remove a portion of the ash and the pyritic sulfur.

Hydrothermal treatment entails basically three processing steps. First, the prepared coal is mixed with the leachant to produce the raw coal slurry. Next, the raw coal slurry is pumped through heated autoclaves, where it is heated to a temperature necessary for extraction of the sulfur and a significant portion of the ash. From the autoclaves, the coal product slurry passes through a heat exchanger where it is cooled. It then exits to a receiving tank.

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*This work was sponsored by the U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, under Contract No. 68-02-2119.

The coal product slurry is then pumped from the receiving tank into a filter where the product coal is separated from the spent leachant. The product coal is then washed to remove the residual spent leachant. The final product is a solid fuel containing reduced concentrations of sulfur and, depending on the leaching conditions and the leachant, ash.

Drying of the fuel to remove the residual moisture is optional. In some uses, it may be desirable to burn the clean coal wet, i.e., as received from the filters. In other cases, removal of a part or all of the residual moisture may be desired. In any event, drying of the coal can be achieved in a variety of commercial available dryers.

The spent leachant may be regenerated for recycle in several ways. One approach entails carbonation of the spent leachant to remove the sulfur as H_2S. The H_2S is then converted to elemental sulfur by the Claus or Stretford Process. The resulting liquor, after sulfur removal, is treated further with lime and then recycled to the mixing (slurry) tank.

COAL PREPARATION FOR COMBUSTION STUDIES

For the EPA combustion study, hydrothermally treated (HTT) coals were prepared from (1) a Lower Kittanning seam coal from the Martinka No. 1 Mine located in West Virginia, and (2) a Pittsburgh seam coal from the Westland Mine located in Pennsylvania. Both coals, even after physical beneficiation, contained sulfur concentrations greater than the equivalent of 1.2 pounds of sulfur dioxide/MM Btu (Federal Sulfur Emission Standards for new sources). Therefore, in order to use the coals as a source of fuel, the coals must be cleaned before combustion or the stack gases scrubbed for SO_x removal.

The HTT coals were prepared in the miniplant facility (a small pilot plant with a production rate of about ¼ ton/day). Sodium hydroxide and a mixture of sodium hydroxide and lime were used as the leachants.

Several types of HTT were prepared:

- Low-sulfur, residual alkali, residual ash in which the residual alkali was sodium. In this case, sodium hydroxide was used as the leachant. Sodium content of the HTT coal was at a level attainable by water-washing. The sodium chemically bound to the coal and that associated with the ash was not removed by the water wash.

- Low-sulfur, residual alkali, residual ash in which the residual alkali was primarily calcium. In this case, a mixed leachant system composed of $NaOH$-$Ca(OH)_2$ was used to desulfurize the coal and to replace with calcium the majority of the sodium normally retained in the coal when $NaOH$ was used as the leachant.

- Low-sulfur, low-ash, low-alkali coal noted as deashed HTT coal. This coal was prepared by washing the sodium hydroxide HTT coal with dilute sulfuric acid.

Analyses of these coals before and after treatment are shown in the following tables.

ANALYSIS OF HTT COALS AND CORRESPONDING RAW COALS

Analysis	Martinka #1 Coal Raw	NaOH Leachant	NaOH-Ca $(OH)_2$ Leachant
Proximate Analysis			
H_2O, %	0.41(0.51)*	3.05(3.65)	0.40(0.56)
Ash, %	19.7(24.65)	13.4(16.03)	28.0(39.1)
Volatile	29.2(36.6)	28.5(34.1)	26.3(36.7)
Fixed Carbon	50.7(63.7)	35.0(65.8)	45.3(63.3)
Heat value, Btu/lb (MAF)	(15,210)	(14,800)	(14,691)
SO_2, lb/MM Btu	2.94	0.97	1.16
Ultimate Analysis			
H_2O, %	0.41(0.51)	3.05(3.65)	0.4(0.56)
Carbon, %	67.0(83.4)	71.4(85.5)	56.4(81.2)
Hydrogen, %	4.4(5.5)	4.5(5.4)	3.8(5.3)
Nitrogen, %	1.21(1.50)	1.3(1.56)	1.1(1.54)
Sulfur, %	1.79(2.24)	0.60(0.72)	0.61(0.85)
Ash, %	19.7(24.65)	13.4(16.03)	28.0(39.1)
Oxygen, % by difference	5.5(6.9)	5.7(6.8)	7.7(10.75)
Sodium, %	0.20(0.03)	4.6(5.51)	1.4(1.96)
Calcium, %	0.13(0.16)	0.15(0.18)	6.6(9.2)

*Numbers in parentheses refer to moisture ash free basis.

ANALYSIS OF HTT COALS AND CORRESPONDING RAW COALS

Analysis	Westland Coal Raw	NaOH Leachant	Mixed Leachant	Deashed HTT Westland Coal
Proximate Analysis				
H_20, %	<0.1(<0.1)*	0.4(0.5)	8.2(10.8)	4.31(4.60)
Ash, %	10.0(11.1)	13.3(15.4)	16.5(21.9)	2.19(2.24)
Volatile	36.9(41.0)	31.2(36.1)	30.4(40.4)	31.5(33.7)
Fixed Carbon	53.1(59.1)	55.1(63.8)	44.9(59.6)	62.0(66.3)
Heat value, Btu/lb (MAF)	(14,950)	(14,320)	(14,100)[a]	(14,349)[b]
SO_2, lb/MM Btu	3.01	1.50[c]	1.50[c]	1.26
Ultimate Analysis				
H_20, %	<0.1(<0.1)	0.4(0.5)	8.2(10.8)	4.31(4.60)
Carbon, %	73.9(82.1)	70.3(81.5)	63.7(84.6)	76.0(81.3)
Hydrogen, %	5.1(5.7)	4.3(5.0)	4.3(5.7)	4.6(4.9)
Nitrogen, %	1.5(1.7)	1.5(1.7)	1.4(1.9)	1.5(1.6)
Sulfur, %	2.02(2.5)	0.93(1.07)	0.67(0.89)	1.05(1.12)[c]
Ash, %	10.0(11.1)	13.3(15.4)	16.5(21.9)	2.19(2.34)
Oxygen, % by difference	7.5(8.3)	4.3(10.8)	5.2(6.9)	—
Sodium, %	0.20(0.02)	2.08(2.4)	0.19(0.25)	0.40(0.43)
Calcium, %	0.08(0.09)	0.20(0.23)	6.0(8.0)	0.84(0.09)

*Numbers in parentheses refer to moisture ash free basis.

[a] Heat value on coal containing 16.4% ash and 9.18% water.

[b] Ash and moisture content of coal used to determine heat value were 1.82 and 7.02, respectively.

[c] Sulfur higher than usual because heater burned out during run. Normally, sulfur content would be equal to or less than 1.2 lb SO_2/MM Btu.

Examination of the data indicates that:

- Environmentally acceptable solid fuel, with respect to sulfur content, can be produced by hydrothermal treatment of Martinka and Westland coals using sodium hydroxide and a mixture of sodium hydroxide and calcium hydroxide as the leachant systems. The clean coals contained a sulfur equivalent of 0.97 to 1.26 pounds of SO_2/MM Btu assuming all sulfur would be emitted during the combustion process. (The high sulfur values of 1.50 pounds SO_2/MM Btu in the sodium hydroxide HTT coal and 1.56 pound SO_2/MM Btu in the deashed HTT coal resulted from incompleted desulfurization caused by failure of one of the autoclave heaters.)

- A small loss in heating value of these coals resulted from the hydrothermal treatment. Treatment of other coals, not on this program, has resulted in a gain in heating value.

- Ash content of the HTT coals is a function of the leachant system. The mixed leachant resulted in an increase in the ash content. In this system, the majority, if not all, of the calcium remained with the coal, whereas about 30 percent of the ash was extracted from the Martinka coal by the sodium hydroxide leachant. Washing the sodium hydroxide leached HTT coal with sulfuric acid resulted in the extraction of 85.5 percent of the ash to produce a product containing 2.25 percent ash.

- Alkali retention by the coal is dependent on the leachant system. Sodium hydroxide leachant produced coals containing about 2 and 5 percent sodium (MAF), respectively. Sodium retention was reduced significantly by using the mixed leachant system.

Although data are not shown, concentrations of certain trace metals — berylium, boron, vanadium, arsenic, lead, and thorium — were reduced significantly by the hydrothermal treatment.

COMBUSTION OF HTT COALS

Preliminary results from the combustion of certain HTT coals in a laboratory-scale combustion unit (Figure 2.4.6) confirmed early beliefs that the use of these coals as a source of energy should result in reduced sulfur dioxide emissions to the atmosphere. Furthermore, the alkali in the HTT coals acts as a sulfur scavenger during the combustion process, thereby reducing sulfur emissions even further.

Combustion unit operation

The laboratory-scale combustion facility used was specifically designed for the evaluation of small quantities of solid fuels.

A procedure was followed in conducting the combustion experiments. To warm up the system, the primary, secondary, and cooling air flow were started and the electrical furnaces and air line heaters were energized. During warm-up, the fuel reservoir was filled and all analytical instruments were calibrated. When the combustion chamber reached 1500°F, a propane flame was established to heat the combustion chamber to 1750°F. When this temperature was reached and all calibrations completed, the fuel feed was started.

After a steady coal flame had been established, the propane was turned off and the combustion experiment was started. During the experiment, the ash was collected, the flue gases were analyzed, the air flows were measured, and the coal rate was determined volumetrically. Upon completion of an experiment, the system was cooled and ash was removed, weighed, and submitted for analysis.

Combustion Results

General Combustion Behavior. In terms of ignition, the HTT coals appeared to ignite somewhat easier than the raw (untreated) coals. This observation is supported by differential thermal analysis shown in Table 2.4.7. In general, the ignition point for the HTT coals was approximately 50° to 75°C lower than the ignition point for the raw coals. No appreciable difference in flame stability between HTT coals and raw coals was observed.

Sulfur Oxide Emissions. The SO_2 level in the flue gases of the burned coal was monitored continuously throughout a given run. Also, for each run, the SO_2 levels were calculated from the sulfur content of the coal and the amount of combustion air assuming total oxidation of the sulfur to SO_2. The measured and calculated SO_2 values are shown in Figures 2.4.8 and 2.4.9.

From a comparison of the measured and calculated SO_2 values, these coals could be burned directly without violating Federal Sulfur Emission Standards. The reduced sulfur levels result, in part, from the hydrothermal treatment and, in part, from the presence of the sodium and/or calcium in the HTT coals which acts as a sulfur scavenger and traps the sulfur before it is (which would be) emitted to the atmosphere. Analyses of the various ashes from the combustions revealed that the sulfur was captured as the corresponding sulfates. The degree of sulfur capture appears to be dependent on the alkali content of the coal, combustion residence time, and may be dependent on the ash composition.

NO_x Emissions. Hydrothermal treatment of coal does not extract the nitrogen. Therefore, the combustion gases from HTT coals contain approximately the NO_x concentration as do those from the raw coals.

Trace Metals Emissions. Hydrothermal treatment of coal results in the extraction of a number of the trace metals. Therefore, trace metals emissions from the combustion of HTT coals should be lower than those from the combustion of the corresponding raw coals. However, measurements have not yet been made to confirm this supposition.

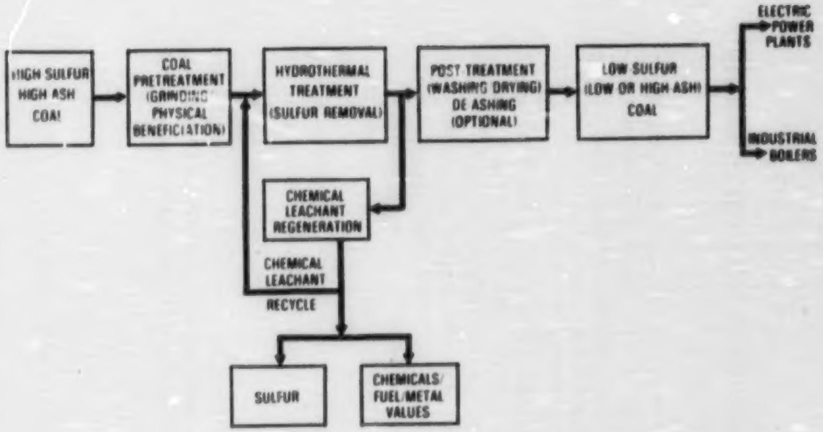
CONCLUSIONS

From the results of the data presented, the following conclusions can be drawn:

- Hydrothermal processing is a technically feasible approach for reducing sulfur in certain high-sulfur coals to environmentally acceptable levels.
- The sodium and/or calcium in the HTT coals acts as a sulfur scavenger during the combustion process, thereby reducing sulfur emissions still further.
- The HTT coals burn as good or better than the corresponding raw coals.

- PROCESS DESCRIPTION
- PREPARATION OF HYDROTHERMAL TREATED COALS (HTT)
- COMBUSTION STUDIES

SYNOPSIS OF PRESENTATION
Figure 2.4.1


HIGH SULFUR HIGH ASH COAL
COAL PRETREATMENT (GRINDING PHYSICAL BENEFICIATION)
HYDROTHERMAL TREATMENT (SULFUR REMOVAL)
POST TREATMENT (WASHING DRYING) DE ASHING (OPTIONAL)
LOW SULFUR (LOW OR HIGH ASH) COAL
ELECTRIC POWER PLANTS
INDUSTRIAL BOILERS
CHEMICAL LEACHANT REGENERATION
CHEMICAL LEACHANT
RECYCLE
SULFUR
CHEMICALS/ FUEL/METAL VALUES

HYDROTHERMAL COAL PROCESS
Figure 2.4.2

COAL SOURCE SEAM	SO_2 EQUIVALENT LB/10⁶ Btu	
	RAW COAL	HTT COAL
1. LABORATORY SCALE		
LOWER KITTANNING	2.2	0.9
UPPER FREEPORT	2.4	0.9
OHIO 6	3.3	1.2
PITTSBURGH 8	4.6	0.9
PITTSBURGH	3.4	0.7
2. PREPILOT PLANT		
LOWER KITTANNING	4.0	1.1
UPPER FREEPORT	2.4	0.8

SULFUR EMISSIONS OF LOW-SULFUR COALS FROM HYDROTHERMAL COAL PROCESS
Figure 2.4.3

METAL	CONCENTRATION, PPM	
	RAW COAL	LEACHED PRODUCT
ARSENIC	25	2
BERYLLIUM	10	3
BORON	75	4
LEAD	20	5
THORIUM	3	0.5
VANADIUM	40	2

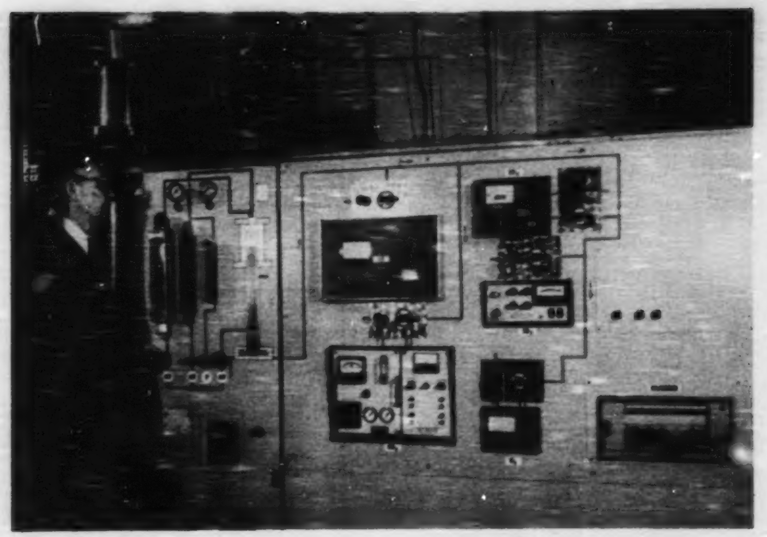
AVERAGE VALUES FOR 3 OHIO COALS: CN 719-SEAM 6, HN 658-SEAM 6A, AND JACKSON-SEAM 4.

SOME TOXIC METALS EXTRACTED BY HYDROTHERMAL TREATMENT OF OHIO COALS
Figure 2.4.4

STATE	SEAM	ASH CONTENT		
		RAW COAL WT%	ACID LEACHED COAL	
			ASH WT%	SODIUM, WT%
KENTUCKY	LEATHERWOOD	5.63	2.00	0.23
KENTUCKY	LEATHERWOOD	5.63	1.85	0.21
OHIO	6	12.8	3.36	0.058
OHIO	6	13.2	5.34	0.048
OHIO	6A	4.63	2.90	0.50
OHIO	8	9.88	1.64	0.033
OHIO	8	9.88	3.24	0.044
PENNSYLVANIA	UPPER FREEPORT	9.64	2.07	0.064
PENNSYLVANIA	8	8.48	1.77	0.043
WEST VIRGINIA	BLOCK 5	5.59	0.71	0.10

LEACHING OF HTT COALS WITH INORGANIC ACIDS

Figure 2.4.5



LABORATORY SCALE COMBUSTION UNIT

Figure 2.4.6

	WESTLAND RAW COAL, LOW-ASH	MARTINKA RAW COAL	WESTLAND COAL SODIUM TREATED	MARTINKA COAL SODIUM TREATED	WESTLAND COAL MIXED LEACHANT	MARTINKA COAL MIXED
STARTING EXOTHERM, °C	233	243	252	263	268	252
IGNITION POINT, °C	426	432	344	360	344	376
SECONDARY EXOTHERM °C	–	–	488	508	494	493
END OF EXOTHERM, °C	615	622	564	578	555	553

DTA PERFORMED WITH STONE MODEL 202 AT 15°C/MIN AND DYNAMIC GAS FLOW OF 94 ML/MIN.

DIFFERENTIAL THERMAL ANALYSES OF COAL SAMPLES IN AN ATMOSPHERE OF AIR

Figure 2.4.7a

	WESTLAND RAW COAL, LOW-ASH	MARTINKA RAW COAL	WESTLAND COAL SODIUM TREATED	MARTINKA COAL SODIUM TREATED	WESTLAND COAL MIXED LEACHANT	MARTINKA COAL MIXED LEACHANT
STARTING ENDOTHERM, °C	400	405	385	375	329	414
PEAK NO. 1, °C	442	455	462	466	467	475
PEAK NO. 2, °C	516	530	519	513	514	520
PEAK NO. 3, °C	555	563	–	–	–	–
END OF ENDOTHERM, °C	584	585	550	557	550	554
PEAK NO. 4, °C	–	–	622	–	678	665

DTA PERFORMED WITH STONE MODEL 202 AT 15°C/MIN AND DYNAMIC GAS FLOW OF 94 ML/MIN

DIFFERENTIAL THERMAL ANALYSES OF COAL SAMPLES IN AN ATMOSPHERE OF NITROGEN

Figure 2.4.7b

COAL TYPE	RAW MARTINKA	CAUSTIC MARTINKA	MIXED LEACHANT MARTINKA
COMBUSTION CONDITION:			
COAL FEED RATE LB/HR	1.27	1.40	1.6
AIR FEED RATE LB/HR	12.26	16.46	16.6
SECONDARY AIR, PSI RATIO	4.0	4.3	–
FURNACE TEMPERATURE, °F	2095	1740	1703

COMBUSTION RESULTS (MARTINKA COAL)

Figure 2.4.8a

COAL TYPE	RAW MARTINKA	CAUSTIC MARTINKA	MIXED LEACHANT MARTINKA
COAL ANALYSIS (moisture free):			
CARBON	67.57	69.58	59.9
HYDROGEN	4.60	4.32	3.74
NITROGEN	1.30	1.41	1.21
OXYGEN	4.3	7.03	5.66
SULFUR	2.00	0.64	0.55
ASH	20.22	17.07	28.3
SODIUM	–	2.61	1.29
CALCIUM	–	0.11	5.95
VOLATILE MATTER	29.21	27.43	26.41
FIXED CARBON	50.83	51.15	45.48
HEATING VALUE, Btu/lb moisture ash free (MAF)	15086	14881	14690

COMBUSTION RESULTS (MARTINKA COAL)

Figure 2.4.8b

COAL TYPE	RAW MARTINKA	CAUSTIC MARTINKA	MIXED LEACHANT MARTINKA
GAS ANALYSIS (AS MEASURED):			
CO_2%	14.4	12.8	14.0
O_2%	1.5	6.3	4.5
CO ppm	705	72	115
NO_x ppm	650	700	690
SO_2 ppm	1910	120	290
THEORETICAL SO_2 ppm	1877	493	495
SO_2 lb/mm Btu (MAF)	2.97	1.03	1.16
SULFUR CAPTURE, %	–	75.67	41.4
RESIDENCE TIME (MILLI SEC)	110	168	169
CARBON BURNOUT, %	–	99.3	–

COMBUSTION RESULTS (MARTINKA COAL)

Figure 2.4.8c

COAL TYPE	RAW WESTLAND	MIX LEACHANT WESTLAND	CAUSTIC WESTLAND	ACID LEACHED WESTLAND
COMBUSTION CONDITION :				
COAL FEED RATE, LB/HR	1.46	1.28	1.3	1.2
AIR FEED RATE, LB/HR	16.6	14.6	14.28	17.8
SECONDARY AIR, PSI RATIO	4.3	7.8	4.4	-
FURNACE TEMPERATURE, °F	1873	2090	1760	1888

COMBUSTION RESULTS (WESTLAND COAL)

Figure 2.4.9a

COAL TYPE	RAW WESTLAND	MIX LEACHANT WESTLAND	CAUSTIC WESTLAND	ACID LEACHED WESTLAND
COAL ANALYSIS (MF):				
CARBON	73.9	69.38	70.36	76.0
HYDROGEN	5.1	4.68	4.44	4.6
NITROGEN	1.5	1.53	1.31	1.5
OXYGEN	7.5	5.66	9.68	10.3
SULFUR	2.02	0.73	0.91	1.05
ASH	10.0	18.0	13.30	2.2
SODIUM	0.02	0.21	1.90	0.43
CALCIUM	0.08	8.0	0.18	0.09
VOLATILE MATTER	36.9	40.4	31.33	31.5
FIXED CARBON	53.1	59.6	55.32	62.0
HEATING VALUE, Btu/lb moisture ash free (MAF)	14955	15066	14388	14349

COMBUSTION RESULTS (WESTLAND COAL)

Figure 2.4.9b

COAL TYPE	RAW WESTLAND	MIX LEACHANT WESTLAND	CAUSTIC WESTLAND	ACID LEACHED WESTLAND
GAS ANALYSIS (AS MEASURED)				
CO_2 %	14.9	12.6	14.2	12.6
O_2 %	3.7	4.9	6.0	5.0
CO PPM	70	55	77	55
NO_x PPM	625	585	770	1075
SO_2 PPM	1115	250	220	525
THEORETICAL SO_2	1610	580	651	660
SO_2 LB/MM Btu MOISTURE ASH FREE (MAF)	3.00	1.27	1.46	1.5
SULFUR CAPTURE, %	30.7	56.9	66.2	20.5
RESIDENCE TIME (MILLI SEC)	157	93	168	163
CARBON BURNOUT, %	95.4		99.4	96.8

COMBUSTION RESULTS (WESTLAND COAL)

Figure 2.4.9c

HOMER CITY COAL CLEANING DEMONSTRATION

J. F. McConnell

Regulations, established under the Federal Clean Air Act Amendments, have set primary and secondary air quality standards. Specific standards of performance under these amendments have been set for sulfur oxide emissions from large stationary sources which include coal burning electric utility boilers. Compliance with the sulfur oxide emission limitations of these standards can be met through control of sulfur burned or by reduction of sulfur oxides in flue gas, i.e., flue gas desulfurization (FGD).

General Public Utilities Corporation (GPU), a holding company, owns three operating companies in New Jersey and Pennsylvania. A subsidiary company, Pennsylvania Electric Company (Penelec) jointly owns Homer City Generating Station, a mine mouth coal fired generating station in central Pennsylvania, with New York State Gas & Electric Corporation, a non-affiliated company. Homer City went into commercial operation in 1969 with two 600 MW capacity units, a third 650 MW unit, scheduled for commercial operation in 1977, is under construction. Dedicated mines (Helen and Helvetia) produce coal for the station with about 2.8 percent sulfur.

Pennsylvania's large stationary source sulfur oxide emission regulations for existing sources outside of air basins permit a maximum emission level of 4.0 pounds of SO_2 per million Btu (MM Btu). Normal run of mine coal from Helen and Helvetia cannot meet this requirement. New source performance standards, applicable to the new unit, are more restrictive and limit emissions to 1.2 pounds of SO_2/MM Btu.

In order to comply with emission standards for SO_2, the Owners of Homer City planned to install a flue gas desulfurization system (FGD) on the new unit. The Owners further planned to construct a coal washing plant to desulfurize coal sufficiently to comply with Pennsylvania's regulations for existing large stationary sources. This coal washing facility, being designed and constructed by Heyl and Patterson, Inc., is currently under construction and will be in commercial operation by April 1977. This coal washing facility features high gravity heavy medium cyclone circuits designed to desulfurize and recover a maximum amount of Btu from the raw coal feed stock. Figure 2.5.2 depicts the flow sheet of this plant which will provide prepared fuel for all of the station. A lime/limestone flue gas scrubber was selected for Unit 3 and placed on order in January 1975.

Indigenous coal deposits in the Penelec service territory, largely the Allegheny series of coal seams, have long been recognized for their susceptibility to desulfurization by so-called coal washing. This is a consequence of both a relatively low percentage of chemically bound organic sulfur and high, but relatively free inorganic sulfur in the pyritic form. Recognizing these inherent characteristics, GPU's R&D efforts in coal utilization have focused on developing advanced coal preparation methods.

Favorable findings from R&D directed at coal washing encouraged the consideration at Homer City of advanced preparation methods as a possible alternative to FGD. A large R&D and engineering evaluation program by GPU/Penelec consultants and Heyl and Patterson on behalf of the Owners, concluded that an advanced state-of-the-art heavy medium cyclone plant, preparing multiple streams of coal — multi-stream coal cleaning system (MCCS) — was capable of processing Homer City coal reserves into compliant fuel without supplemental FGD. In August 1975, the Homer City Owners made the decision to proceed with the design and construction of new low gravity heavy medium cyclone circuits to accomplish deep coal washing in an MCCS concept to meet new stationary source performance standards for Unit 3. The flue gas scrubber was cancelled. Figure 2.5.3 depicts the Homer City MCCS concept.

A multi-stream coal cleaning system, per se, is not a new idea — industry has used the concept. EPA discussed the concept in their report (I-A-6) on the High Sulfur Combustor Power Plant in April 1973. The GPU-Penelec MCCS system, as the Homer City Owners, NYSE&G and Penelec are applying it, includes a number of innovative applications and extensions of existing technology to multi-stream coal processing. These innovations relate to:

- Extending the range of application of heavy medium cyclone equipment to smaller sized coal fractions (100-mesh from the usual 28-mesh bottom size).
- Substitution of full stream electro magnetic separators for drain and rinse screens in the 9-mesh x 100-mesh coal circuit for recovering magnetite.
- Extending the range of operating specific gravity of heavy medium cyclones to 1.8 at the upper end and to 1.3 at the lower end.
- Development of a novel control system for tighter control of the specific gravity of operation in the nominal 1.3 specific gravity circuit operating on fine size coal.

THE COAL CLEANING APPROACH

The clean coal quality requirements which Homer City coals must meet to satisfy new source emission requirements of 1.2 lbs of SO_2/MM Btu are:

- 0.6 lb S/MM Btu
- 0.9% S or less
- 15,000 Btu/pound or greater

A study of the coal bed seam characteristic information in the U.S. Bureau of Mines reports RI 7633 and 8118 provided considerable data on these coals and on the Upper and Lower Freeport and Lower Kittanning Seams, which comprise the bulk of the reserves committed to the Homer City Station. Comparative rank of Homer City Station reserves is shown in Figure 2.5.5. To meet clean coal quality requirements for the average, and not the best of coal reserves, it was evident that coal cleaning objectives must involve cleaning circuits capable of operating effectively at a specific gravity of separation of 1.3 and that the coal supply should have recovery characteristics that would provide the required quantities of Btu needed for each of the generating units. The targeted requirements of fuel for the Homer City Generating Station are as follows:

	Unit 3 (new source)	Units 1 & 2 (existing sources)
Btu/year × 10^{12}	38.5	74.7
Percent of Requirements	34.0	66.0
Lbs. S/MM Btu	0.6	2.0

The expected preparation plant performance, with the final flow sheet design, discussed later, is as follows:

	Units 1 & 2	Unit 3	Refuse
Recovery (weight percent)	56.2	24.7	19.1
Recovery (Btu percent)*	61.6	32.9	5.5 (Loss)
Product Btu/pound (dry basis)	12549**	15200	3367
Ash Percent	17.8	2.8	69.7
Sulfur Percent	2.24	0.88	
Pounds Sulfur/MM Btu	1.79	0.58	

* Gross recovery 94.5 percent net recovery is 93.5 with losses for thermal dryer included.

** Blend of middling and clean coal.

THE COAL CLEANING PLANT DESIGN

The detailed coal preparation plant arrangement developed by the Homer City Coal Preparation Plant contractor, Heyl and Patterson, Inc., and by GPU, Penelec and its consultants, incorporates the following designs as illustrated in Figure 2.5.14.

Crushing and Classification

A portion of the cleaning plant is dedicated to crushing and size classification. Provision is made to selectively crush all major sources of supply to the cleaning plant in variable speed cage crushers to control the production of plus ¼-inch and minus 100-mesh material while optimizing the release of pyrite and ash.

Coarse Coal Cleaning

The coarse coal cleaning circuit cleans plus ¼-inch coal in heavy medium cyclones at 1.8 specific gravity. Cleaned plus ¼-inch coal becomes part of the moderately cleaned middling coal blend.

Medium Coal Cleaning

The medium coal cleaning circuit cleans ¼- × 9-mesh coal in two stages of heavy medium cyclones. The first stage cleans at 1.3 specific gravity. The clean coal overflow product of this circuit is available as intensively cleaned coal for use in Unit 3. Surplus 1.3 float product from this stage is blended into the moderately cleaned middling coal. Underflow from the first stage is recleaned in the second stage of heavy medium cyclones at 1.8 specific gravity. Underflow from this stage is refuse coal, underflow is 1.8 float — 1.3 sink and is blended into middling coal.

Fine Coal Cleaning

The fine coal cleaning circuit cleans 9-mesh × 100-mesh coal in heavy medium cyclones at 1.3 specific gravity. In this circuit, underflow from the classifying and deslimming screens is pumped to 14-inch classifying cyclones. Underflow containing mostly 9-mesh × 100-mesh coal is cleaned at 1.3 specific gravity in heavy medium cyclones. Overflow product is partially dewatered and washed of fines in spiral classifiers. This product makes up the major portion of intensively cleaned coal for Unit 3.

Fine Coal Scavaging Circuit

The fine coal scavaging circuit deals with 9-mesh × 100-mesh, 1.3 specific gravity sink coal and minus 100-mesh coal. Coal prepared in this circuit is blended into moderately cleaned middling coal. Coarser material is cleaned in hydro-cyclones. Hydro-cyclone underflow is sent over Deister tables for pyrite removal.

DESIGN DISCUSSION

The Homer City Coal Cleaning plant is designed to remove the maximum technically feasible amount of pyritic sulfur from the intensively cleaned product for Unit 3 consistent with the Btu requirements of that Unit. The coal preparation plant arrangement incorporates the following design features:

- Provision has been made to selectively crush all major sources of supply to the cleaning plant (Helen, Helvetia and outside truck coal) when needed to provide additional capability to meet sulfur quality and Btu requirements. The most favorble coals will be crushed to amplify their impact on intensively cleaned product. Cleaning plant design provides for crushing up to 75 percent of design tonnage input to maximum of 10 percent plus ¼-inch oversize.

- The intensive cleaning circuits will be designed to operate an effective specific gravity of separation of 1.3. Feed will be classified to ¼-inch × 9-mesh and 9-mesh × 100-mesh and dealt with in independent circuits. Operating conditions and medium gravities will be optimized for sulfur reduction and Btu yield in each classified size heavy medium cyclone circuit.

- Recovery of magnetite in the 9-mesh × 100-mesh coal fraction will be accomplished with electro-magnetic separators — drain and rinse screens, normally used for this purpose, will not be used.

- Heavy medium cleaning circuits assure sharpness of separation through application of the following design concepts:

  — Classified feeds

  — Light apex volumetric loadings in the cyclones

  — Use of fine particle size medium

  — Control of medium viscosity by reduction of bituminous contamination

The most obvious feature of the Homer City Coal Cleaning plant is that it deliberately deals with a fine size consist of coal at low gravity with heavy medium cyclones. Figure 2.5.15 illustrates the well known characteristic of the Allegheny series of coals; that size reduction releases pyrite and ash. Based on float-sink data on run-of-mine coal for Homer City, insufficient margin for sulfur reduction and Btu yield is attainable from 1¼-inch × 100-mesh coal. The relative quality and yield from ¼-inch × 100-mesh size fraction is substantially better, hence the desirability of crushing. Some Btu will be lost below 100-mesh size and the washability of crushed 1¼ × ¼-inch coal will not equal the natural sizes, nevertheless, overall improvement results as inferred in Figure 2.5.16.

Heavy medium cyclones have been selected because of the large amount of near gravity material at 1.3 specific gravity. The inherent sharpness of separation of heavy medium cyclones is essential for quality and Btu recovery. Heavy medium cyclones are employed in the high gravity circuits to assure the maximum overall Btu recovery.

There is obviously no purpose in extending the complexity, difficulty, and cost of coal preparation beyond that which is necessary to achieve the required quality of coal from the available coal reserves. The incentive to clean steam coals has existed mainly to reduce ash content to meet boiler specifications for fuel or to reduce transportation cost. The application of coal preparation for substantial sulfur reduction to meet emission regulations is not common, and introduces the difficulty that the products must consistently and reliably meet quality standards hour by hour, or the power plant user is in technical violation of State and Federal Regulations. The same requirement applies to FGD. The use of a multi-stream coal cleaning system does offer one environmental advantage, however. Even if, at certain times, excessive misplaced material is generated by the low specific gravity circuits, the net sulfur in the combined low and high gravity circuits remains unchanged and the total sulfur oxide emission and environmental consequence from a multi-unit station will be unchanged.

CONCLUSIONS

- The multi-stream coal cleaning concept, as discussed in this paper, can provide an alternate and possibly more economical approach for the control of SO_2 emissions from coal fired boilers if the proper coal reserves are available. It has the flexibility, from a systems point of view, to be used singly or in conjunction with flue gas desulfurization.

- The decision of the Homer City owners to install an MCCS system is not a risk-free decision. There are risks associated with unknowns in the character of coal reserves still to be mined that could adversely affect product quality. This might force a retrofit with a partial flue gas scrubbing or chemical system to incrementally improve sulfur quality. There are also risks not discussed in this paper associated with the operation of boilers and precipitators with a 3 percent ash, low sulfur fuel.

- There is a need for additional research and development work in a number of areas of cleaning plant design. Some of these are:

  — Development of efficient and cost effective techniques to physically clean the minus 100-mesh coal size fraction, which has the most significant potential for sulfur reduction and Btu yield improvement.

  — Development of techniques to dewater and handle fine coal and refuse.

  — Determination and better understanding of the optimum loadings and operating parameters of equipment as applied in low gravity cleaning circuits.

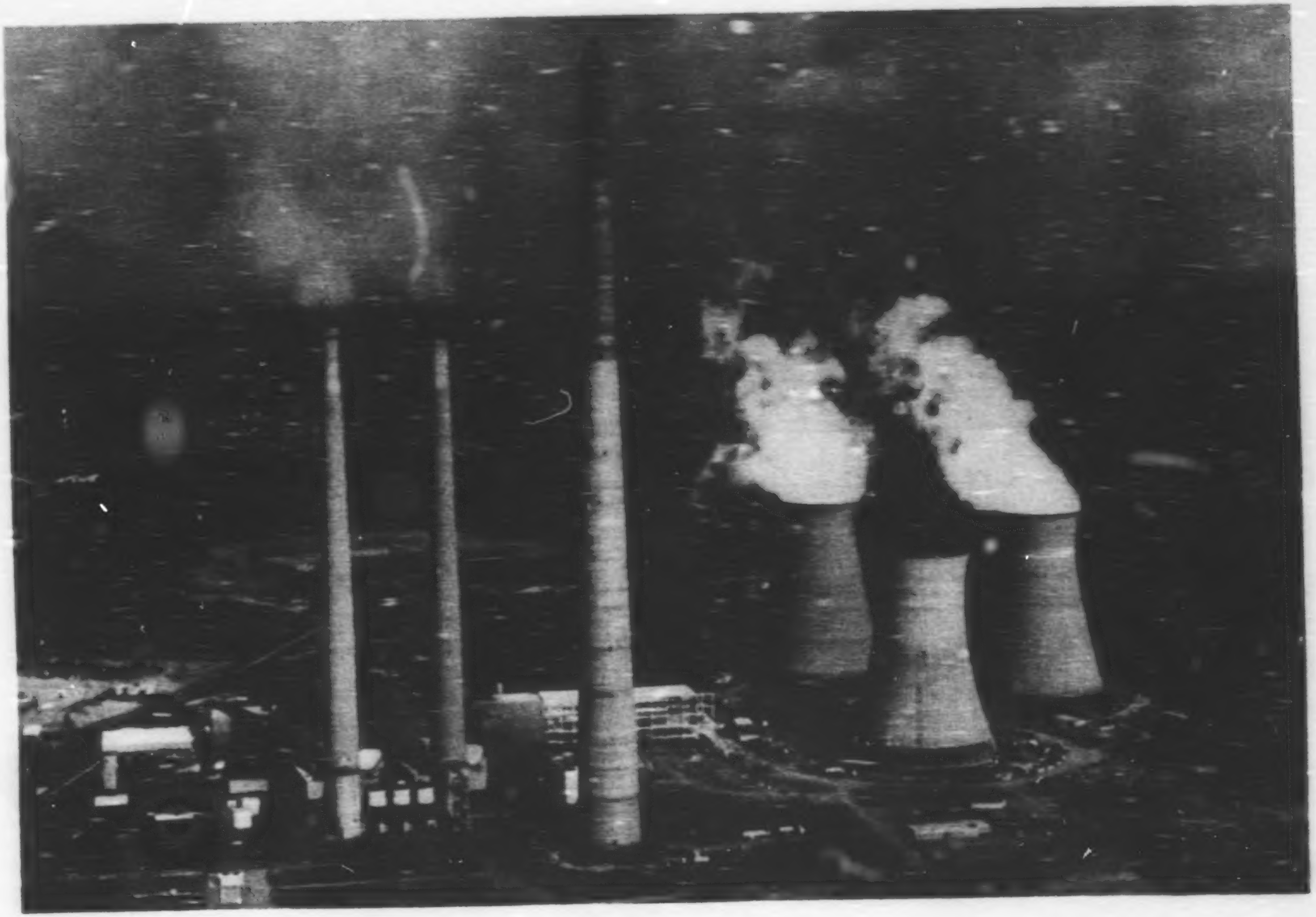
- There is a need to recognize the inherent variability of coal quality and to reflect this through the application of a longer time constant in environmental regulations. This would permit more economical designs that would accomplish the same environmental improvements.

REFERENCES

1. Deurbrouck, A. W. Sulfur Reduction Potential of the Coals of the United States, Bureau of Mines Report of Investigations, 1972.

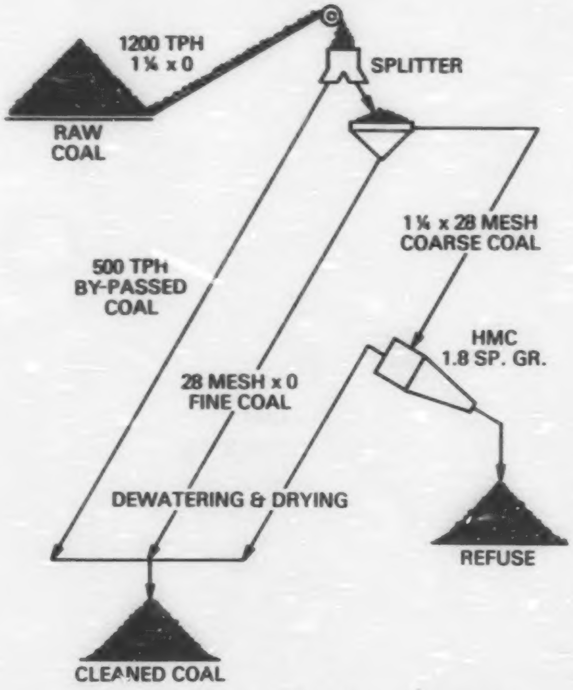
2. McConnell, James F., and Statler, Charles. Multi-Stream Coal Cleaning Strategy for Control of Sulfur.

3. Statler, C. W. Multi-Streams Coal Washing, A Systems Approach for the Control of Sulfur.



**OVERVIEW OF HOMER CITY
GENERATING COMPLEX**

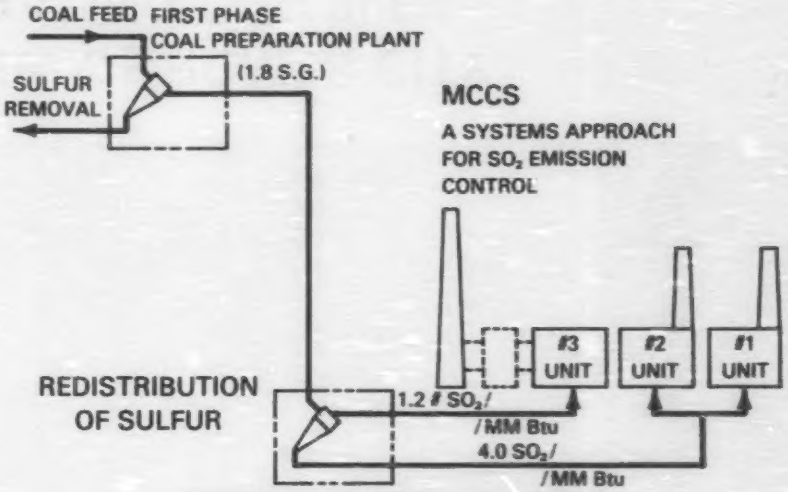
Figure 2.5.1


1200 TPH
1¼ x 0
RAW COAL
SPLITTER
500 TPH BY-PASSED COAL
28 MESH x 0 FINE COAL
1¼ x 28 MESH COARSE COAL
HMC 1.8 SP. GR.
DEWATERING & DRYING
REFUSE
CLEANED COAL

HOMER CITY COAL CLEANING

FIRST PHASE PREPARATION PLANT

Figure 2.5.2


COAL FEED
FIRST PHASE COAL PREPARATION PLANT
(1.8 S.G.)
SULFUR REMOVAL
MCCS
A SYSTEMS APPROACH FOR SO₂ EMISSION CONTROL
REDISTRIBUTION OF SULFUR
#3 UNIT
#2 UNIT
#1 UNIT
1.2 # SO₂/ /MM Btu
4.0 SO₂/ /MM Btu

HOMER CITY COAL CLEANING

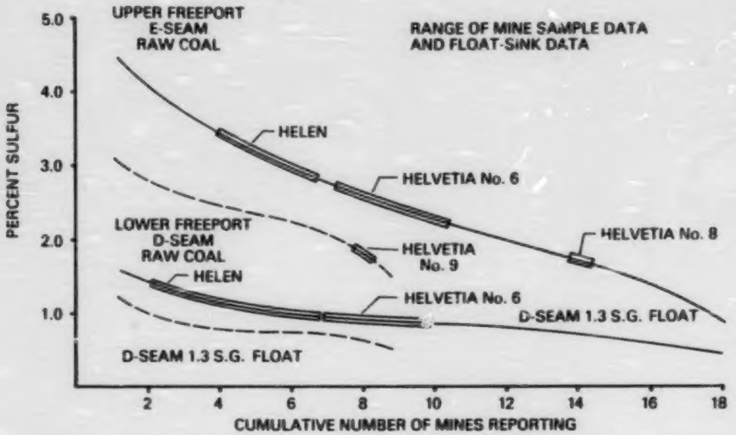
Figure 2.5.3

COST COMPARISON — COAL PREPARATION VS FGD

CAPITAL INVESTMENT FOR SO_2CONTROL, $MM		*FGD*	*MCCS*
COAL PREPARATION FACILITIES	SCHEDULED IN SERVICE DATES		
ORIGINAL PLANT (FOR USE WITH FGD)	MAR. 1977	18	18
MCCS ADDITION	DEC. 1977		32
FGD		59	0
SUB TOTAL		77	50
ANNUAL REVENUE REQUIREMENTS FOR SO_2 CONTROL, $MM			
FIXED CHARGES		11.6	7.5
OPERATING AND MAINTENANCE EXP.			
FGD		10.6	0
COAL PREPARATION		3.2	7.6
SUB TOTAL		25.4	15.1

HOMER CITY GENERATING COMPLEX
ALTERNATIVE SO_2 CONTROL STRATEGIES

Figure 2.5.4



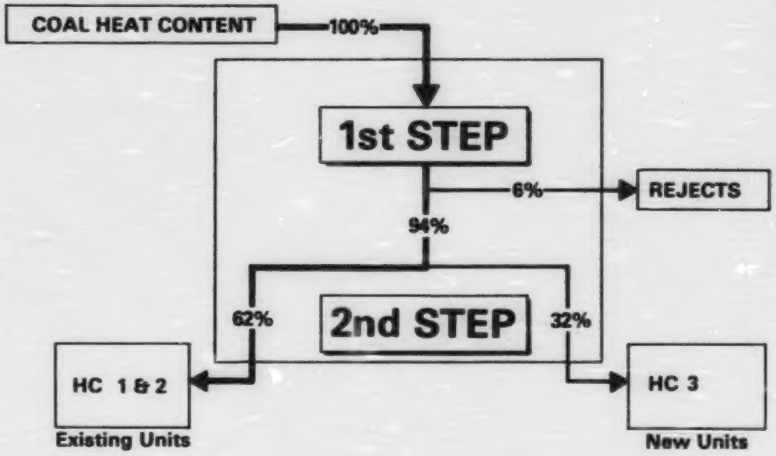
WASHABILITY DATA, PA. MINES VS. HELEN & HELVETIA MINES

Figure 2.5.5

a.	0.6 lb SULPHUR/MM Btu
b.	0.9% SULPHUR
c.	15,000 Btu/lb
d.	2.5 TO 3.5% ASH

MCCS DEEP COAL CLEANING REQUIREMENTS

Figure 2.5.6

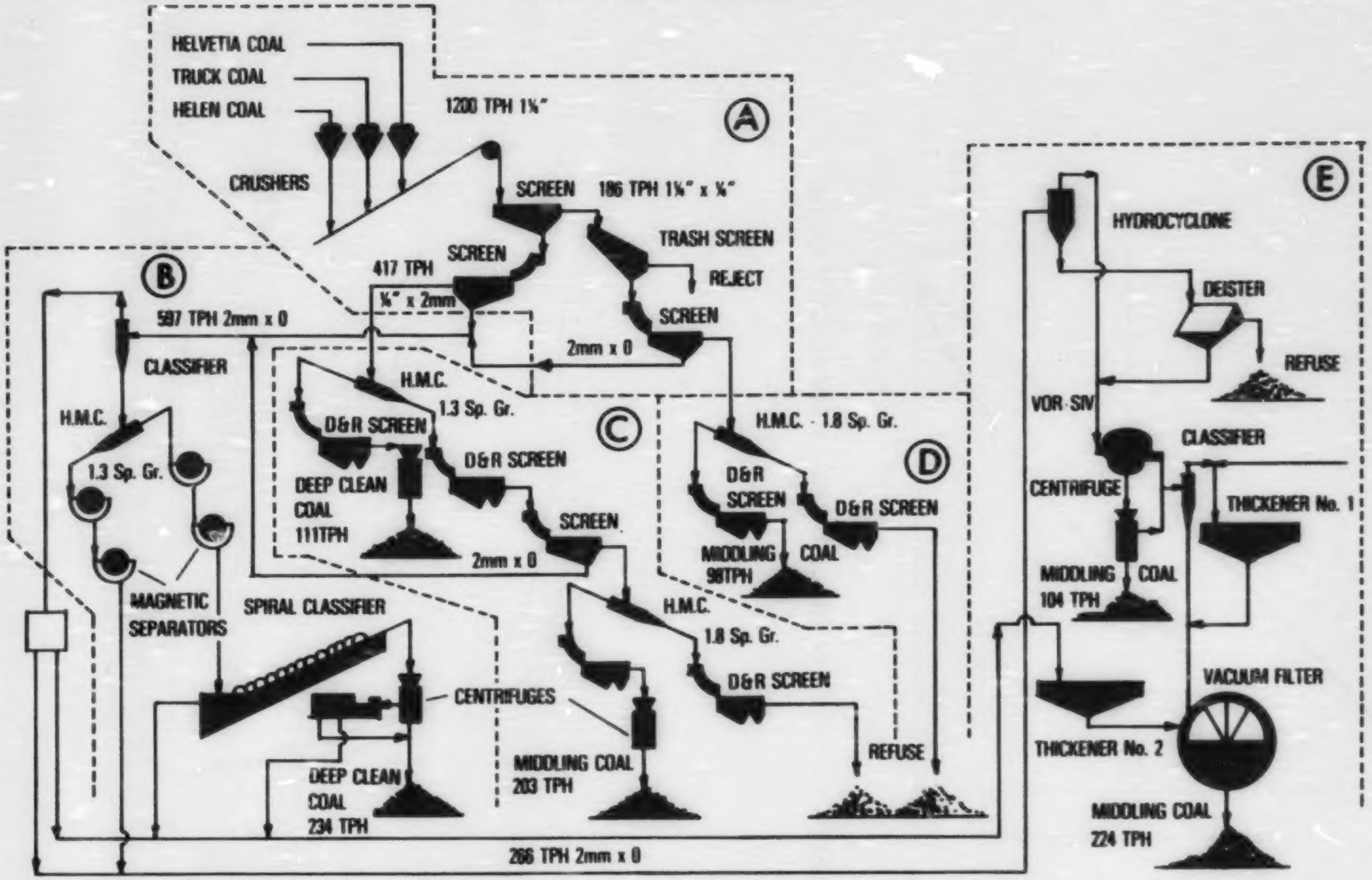

COAL HEAT CONTENT
100%
1st STEP
6%
REJECTS
94%
62%
2nd STEP
32%
HC 1 & 2
Existing Units
HC 3
New Units

MCCS COAL HEAT CONTENT BALANCE

Figure 2.5.7

EDITOR'S NOTE: Since Figures 2.5.8 through 2.5.13 are identical except for individual highlighting of a subsystem, they are not included here.

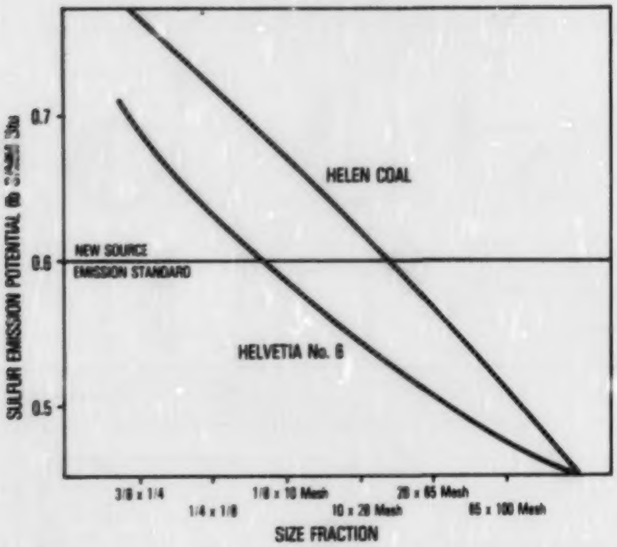
SIMPLIFIED DIAGRAM
COAL CLEANING CIRCUITS


HELVETIA COAL
TRUCK COAL
HELEN COAL
CRUSHERS
1200 TPH 1¼"
Ⓐ
SCREEN
186 TPH 1¼" x ¼"
TRASH SCREEN
REJECT
SCREEN
417 TPH
¼" x 2mm
SCREEN
2mm x 0
Ⓑ
597 TPH 2mm x 0
CLASSIFIER
H.M.C.
1.3 Sp. Gr.
MAGNETIC SEPARATORS
SPIRAL CLASSIFIER
CENTRIFUGES
DEEP CLEAN COAL 234 TPH
H.M.C.
1.3 Sp. Gr.
Ⓒ
D&R SCREEN
DEEP CLEAN COAL 111TPH
D&R SCREEN
SCREEN
2mm x 0
H.M.C.
1.8 Sp. Gr.
D&R SCREEN
MIDDLING COAL 203 TPH
REFUSE
H.M.C. · 1.8 Sp. Gr.
Ⓓ
D&R SCREEN
D&R SCREEN
MIDDLING 98TPH
COAL
266 TPH 2mm x 0
Ⓔ
HYDROCYCLONE
DEISTER
REFUSE
VOR·SIV
CLASSIFIER
CENTRIFUGE
THICKENER No. 1
MIDDLING 104 TPH
COAL
VACUUM FILTER
THICKENER No. 2
MIDDLING COAL 224 TPH

Ⓐ CRUSHING & SIZE SEPARATION
Ⓑ FINE COAL – DEEP CLEANING
Ⓒ MEDIUM COAL – CLEANING
Ⓓ COARSE COAL – CLEANING
Ⓔ FINE COAL – SCAVENGING

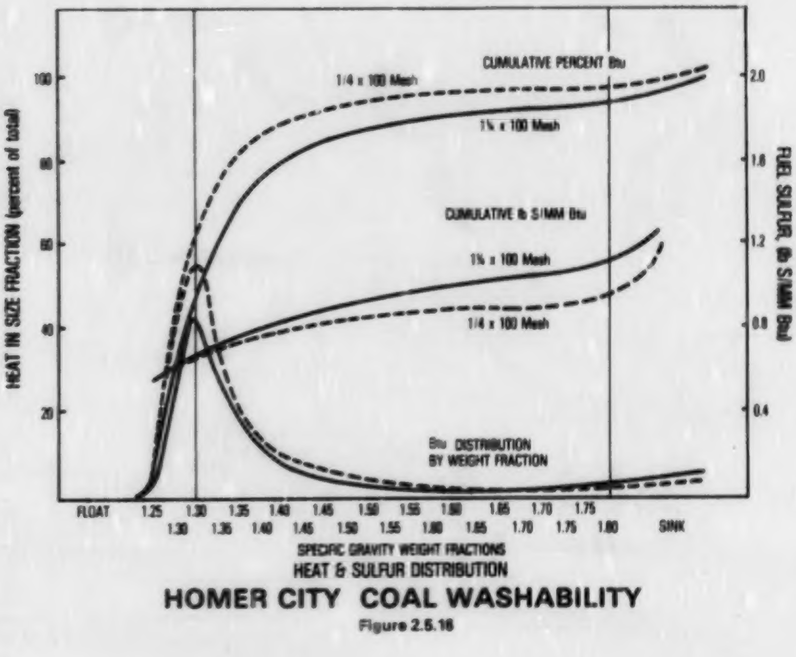
HOMER CITY — MCCS

Figure 2.5.14



EFFECT OF SIZE ON QUALITY FOR HOMER CITY COAL

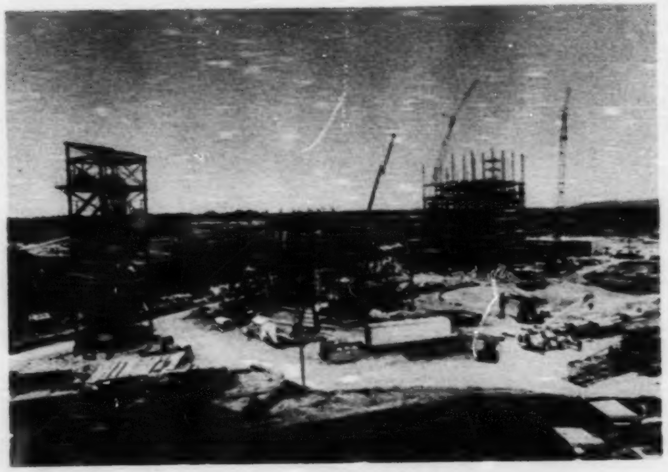
Figure 2.5.15



HEAT & SULFUR DISTRIBUTION

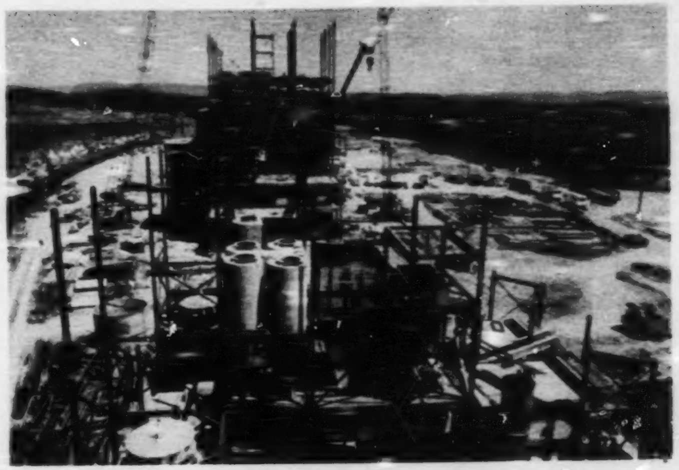
HOMER CITY COAL WASHABILITY

Figure 2.5.16



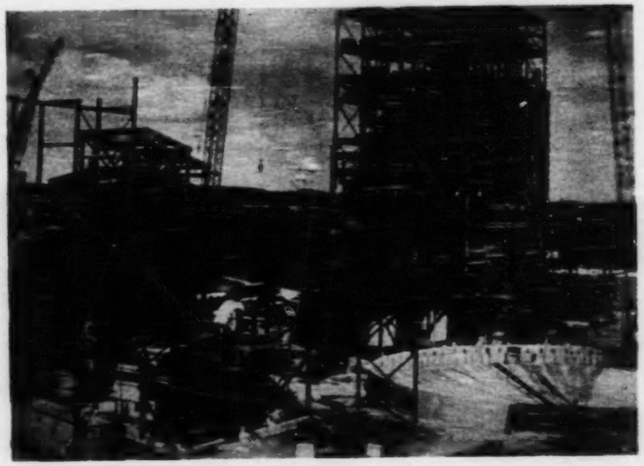
HOMER CITY SITE: EARLY CONSTRUCTION
(24 MAY 76)

Figure 2.5.17



HOMER CITY SITE: EARLY CONSTRUCTION
(24 MAY 76)

Figure 2.5.18



HOMER CITY SITE AS OF AUGUST 30, 1976

Figure 2.5.19

DISCUSSION

William N. McCarthy Jr.
Moderator

After the papers were presented the authors assembled for a discussion with the audience. The discussion revealed interest in the validity and usefulness of data and methodology of on-going programs. The final disposition of contaminants and pollutants, and the chemical and physical changes resulting in coal ash from different processes and coals were examined. Elements from coal being introduced into the environment in trace quantities, but in unprecedented volume, were of particular interest and some concern. The need for determining and evaluating these contaminants was expressed. The merit of averaging data of coal cleaning characteristics by regions was challenged, and the necessity of linking specific coals to specific processes or combinations of pollutant control processes was discussed.

Considerable interest in the economics of processes was expressed; and the need for such data endorsed. However, little economic data are available. It was also observed that the Environmental Protection Agency and the Federal Power Commission are working to merge data based on environmental information to provide more responsive and effective programs.

The source for the following discussion was a tape recording made at the meeting. As the audibility of the tape was not perfect in every instance due to a number of participants speaking simultaneously, this is not a verbatim report.

CHAIRMAN WILLIAM MCCARTHY: Do we have any questions?

PAUL CHEH, ONTARIO HYDRO: Yes. I have a question for Dr. Issacs. In developing your (pollution) control strategy, I gather your objective function is to minimize the cost of the system. Is that right?

DR. GERALD ISSACS, PEDCO: Yes, that's correct.

CHEH: Have you done any analysis in terms of comparing different systems and how to derive a reasonable — I don't know how to define reasonable — allocation for pollution control strategy for such systems?

ISSACS: Yes, we're looking into coming up with a minimum cost strategy for some other systems right now in some on-going work. We are further developing a computer program that will optimize the selection of the coals to be used, the distribution of those coals among the power plants, and the optimum placement of coal cleaning plants and flue gas desulfurization systems within a given matrix of power plants.

CHEH: Could you be specific as to what type of program you intend to use?

ISSACS: I'm not sure I am qualified to answer. I am not doing the programming on it. I think we started with a linear type (inaudible) computer program for optimizing sulfur oxide emission control using combinations of coal cleaning and flue gas desulfurization for processing different coals. But I'm not sure this is going as well as expected and we may be looking at some different avenues.

DR. H. R. HICKEY, of TVA, asked about the cost per kilowatt hour of flue gas desulfurization.

The cost of the scrubber for Homer City was discussed.

MR. JAMES F. MCCONNELL, GENERAL PUBLIC UTILITIES: It may appear to be $35 per kilowatt if they're using one third of the station capacity. The FGD system applied to the actual firing system

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control would probably be closer to $80 per kilowatt. Divided over a coal station's generating capacity, it will come out something like $30 per kilowatt, I believe. Our numbers were closer to $60-$85 per kilowatt for an FGD system.

MR. TIM DEVITT, PEDCO: The FGD system, we assume, had an 85 percent sulfur removal capability so it only needed 42 percent removal capability, only about half . . .

Several talking at once and inaudible . . . a yes, I think so, yes.

ISSACS: Does it include sludge disposal facilities?

MCCONNELL: Yes.

ISSACS: Our numbers included sludge disposal and capital investment.

TOM PONDER, PEDCO: You'll find you have to have the same bases for everyone so cost estimates will come out the same. In many cases particulate control costs are included along with the SO_2 part of it, and also you'll see stack process costs included. So if we could get everyone on the same basis on the same process it would help. That's a big problem in this kind of work.

HERBERT SPENCER III, WESTERN PRECIPITATION DIVISION OF JOY MANUFACTURING: What's the effect of pyritic sulfur removal from coal prior to burning on a particulate collector? You're well aware many manufacturers in the past used sulfur content as a means of deciding how big to build their units. I did notice though that in the Battelle system it appeared you got some changes in ash chemistry that might affect ash resistivity in a positive way . . .

JAMES KILGROE, EPA: We didn't exactly get into that in any extent in our discussion today. You know that's quite an element in our program and we are being supported by other groups down at Research Triangle Park. In our new contracts we're looking at what is the prospect when we start removing sulfur. What are the elements of the change of resistivity and flexibility in removability in fly ash? That is some of the stuff Battelle is doing. They are collecting fly ash from combustor gas and are trying to determine what the resistivity is by various methods. There is also a point of view the resistivity is in the combustion process, and how the particles are formed will also affect collectability. That is something we want to look into and determine whether or not combustor tests are really giving something that is really meaningful or whether we have to get especially constructed combustor sets like the Bureau of Mines is trying to develop and the Australians have.

E. P. STAMBAUGH, BATTELLE COLUMBUS: We have measured the resistivity of a few of our samples and found the resistivity appears to fall within the range of about 10^8 to 10^{10} centimeters which is within the range of collectability. But there will need to be more work done in that area. I don't recall what the resistivities were on the broad range of coals, but on the HTT coals they were within the vicinity of 10^8 to 10^{10}.

SPENCER: I expected to see a reduction since it looked like, at least in the western coals, you had a higher sodium content and appear to attach sulfur to the ash.

STAMBAUGH: Well, during the leaching of the coal, the resistivity changes with the acid to base ratio of the constituents, as we add higher sodium or calcium. We are changing the composition of the ash by quite a bit by extracting bismuth, silica, and trace metal values which will affect it.

SPENCER: One other question along that line. What about the effect on boiler operations of the fusion temperature of the ash? Do you have slagging problems or not?

STAMBAUGH: It looks as if the slagging temperatures may be reduced in some cases, raised in other cases. So there still needs to be more work done in that area, which we will be doing for EPA.

MR. ART LYALL, RESEARCH DEVELOPMENT: What happens to the solubilized trace elements — lead, antimony, and the other compounds in the process?

STAMBAUGH: They would go with the spent leachant. We find during leachant regeneration by treatment with CO_2 that a large number of them precipitate. We have not really conducted enough work yet to see if they will build up on recycle. But, we would hope to develop a method for recovering these trace metal values.

DR. EUGENE WEWERKA, LASL: Along that same line, I wonder if Bob Meyers might comment about the same topic. You indicated in your talk, I believe, that there were trace contaminants removed from the coal. Could you tell us what they are and where they end up in the process and so on?

DR. ROBERT A. MEYERS, TRW: In our process we are making iron sulfates as a product of the process. We are not making USP grade iron sulfates, but, rather, iron sulfates that contain their natural abundance of trace elements which are obtained from the coal.

MR. SAHRAB HOSSAIN, CATALYTIC, INC: Is there any waste water discharge from coal cleaning plants? If so, how do you treat it?

MCCONNELL: Basically there is not. The take up water is supplied, and the water that is lost from the plant is either through the evaporator or some amount of moisture attached to the refuse. Basically there is no waste water stream.

KILGROE: There are new proposed EPA effluent guidelines for new preparation plants which essentially say that there will be no discharge. They are to recycle all the water. On existing plants, of course, there is some discharge depending upon state and local regulations. The industry is progressing toward no discharge.

TIM SALOWITZ, EPA: About the refuse program that's generating from coal cleaning and preparation techniques: Currently, it is being stored on site. Is that the dominant technique? As future state and federal regulations for industrial wastes get tighter, what's the current thinking on disposal techniques for the future?

KILGROE: I guess that's one of our major concerns. We have a large contract calling for environmental assessment of coal preparation processes: What are the environmental impacts of cleaning coals? How do you get rid of residues? What are the leachant problems?

The work we have been doing with LASL is really looking at the leach outs from coal preparation plant wastes. We are going to look at that considerably. I might mention that in the previous "incarnation" I was involved with EPA's solid waste program for about four years. So I think we're aware of that problem.

MR. TIM FIELDS, EPA: What is the current practice, storing on site? Stockpiling?

KILGROE: Yes. Would anyone like to comment on that?

WEWERKA: The problem of solid waste from coal preparation probably can be considered as a two pointed situation to look at from here on out. There are regulations and guidelines forthcoming for the disposal practices of these materials. They'll have to be disposed of in such a way that there aren't any structural problems and that types of effluents are at a minimum. The type of guidelines Jim just mentioned apply not only to the coal preparation plants, but also to waste materials from the plants.

The amount of dissolved materials or contaminants which will be allowed in waste water are very, very small. There is no question that in the future, disposal must be done in an environmentally compatible way. The problem is the material which already has been disposed of, which I mentioned this morning. There are about 300 billion tons of this stuff around the countryside. This is a different aspect. It is not that the technology can't be found that will come up with a way to treat those waste materials but, proving the legal responsibility for them is a problem. A great number are completely abandoned and nobody wants to take responsibility for them. As to who eventually will have to bear the cost of cleaning up that aspect of the situation is not at all clear at this point.

MCCONNELL: I think there is an assumption here that coal preparation will create large quantities of waste material that hitherto we didn't have. But we still have to remember that 25 percent of the coal that comes out of the ground is mineral matter, and it turns out to be mine refuse, bottom ash, or fly ash. We've always had it. We're not creating it. We're just getting it in a different form, and it may be more or less difficult to deal with. But we are not, in fact, creating massive new amounts of material that otherwise wouldn't occur. It is, and always has been a part of a mining enterprise to produce waste materials that are not put back underground again, at least by present technology.

UNIDENTIFIED VOICE FROM AUDIENCE: But it has a lot more sulfur in it.

MCCONNELL: Right. The sulfur is in it instead of in the air.

MR. S. Z. ALTSCHULER, USGS: Whereas it is true we've always dealt with wastes and their hazardous trace element burden, there is one aspect of the present technology that differs from the past, and that is the necessity to treat these extremely large quantities of coal at one or two sites. This is in contrast to the small quantities burned in the past. So consider something like beryllium falling out in ash. You're going to be loading the countryside if it is in fly ash fallout, with much more beryllium, ultimately, than you may have had ever before, despite the fact the concentrations may not be that much different. So there is a need for concern, more now than in the past, not because we know more about toxicities, but because we are going to be adding to the burden, maybe by an order of magnitude.

MR. ALEX WEIR, SOUTHERN CALIFORNIA EDISON: We've published the work we did for the Electric Power Research Institute on trace elements in fly ash and in scrubber sludge. I think what you're not taking into account is that elements like beryllium are effectively removed by electrostatic precipitators and scrubbers. Also, you're talking about well over 90 percent of this material burned being removed in solid form. What we found was that in scrubber sludge there is very little leaching of this material into ground water. It depends, of course, on the type of soil; but it would be hundreds of years before it would affect drinking water standards from an unmined plot.

ALTSCHULER: I am not disputing the fact that we can handle these problems, but we have to take cognizance of the potential because the type of sludge or waste you get may be low in beryllium as you say, but in other instances it gets quite high. The Radian Study that was conducted by Radian Corporation on North Dakota lignites shows quite a variation in the contents of the trace elements from three different types of waste productions for the same lignite. In one case, for example, molybdenum went up to 55 parts per million in the physically collected ash from the particulate collector; whereas for another type of fly ash, it was much lower. It is not that these things are insurmountable problems, but they have to be looked at.

MR. DOAN PHUNG, INSTITUTE OF ENERGY ANALYSIS: I would like to ask a question of the gentlemen who gave the paper on trace elements on coal. I have seen a sample of coal, I think from North Dakota, that has something like 100 parts per million of uranium in the coal, and I want to find out how widespread these types of coal are.

ALTSCHULER: That type of concentration of uranium is quite widespread since it has been noticed in many types of lignites and coals, although it is restricted to specific geologic situations, notably where you have uranium-rich material overlying coal. The material itself is somewhat unstable, such as volcanic ash. This has appeared in a number of instances in North Dakota lignite and also the Texas Lignite fields. There is a natural leaching of the ash, and a sodium carbonate rich solution develops. It leaches uranium from the vitrifying ash. As this solution seeps down, it contacts a coal bed immediately underlying, and the coal kind of strips the uranium out. This type of process is evident in the distribution of uranium within these lignites and coals.

It is usually quite rich in the upper part of the bed and declines very rapidly below. In other words, the affinity for organic matter stripping action results in the uranium being concentrated in the uppermost parts of the beds. In the early 1950's these types of resources were thought of, especially in North Dakota, as uranium recovery potentials. As a fact, there is some recovery practiced in some of the lignites in Texas which became uraniferous in the same manner.

PONDER: Would anyone comment on what clean coal can do for boiler reliability or heat ratios?

MCCONNELL: We thought we might see, subjectively, 5 percent improvement in reliability. I really don't think we'd see much change in heat rate.

PONDER: The boiler is not designed for processed coal. It was designed for run of mine coal; not designed for very low ash, high Btu coal.

MCCONNELL: Right. You may have more, or you may have less of a slagging problem. We think it would be about the same. The slagging problem is not directly proportionate to amount of ash, but more a matter of character of the coal. You never know until you try one out.

MR. JACK MCGOVERN, CARNEGIE MELLON UNIVERSITY: I'd like to know if anyone can tell me whether the physical cleaning of coal will change the storability of it — including chemical cleaning. Whether the properties will deteriorate differently on storing?

MEYERS: There've been a number of studies which have related pyrite content to the weathering of coal and which try to attribute weathering and spontaneous combustion to the pyritic level. The correlations haven't been all that good. There is a general suspicion that high pyrite coal weathers to a higher degree and can ignite more easily in a storage situation than low pyrite coal.

MCGOVERN: How about any decrease in the heating value of coal just from sitting in piles?

MEYERS: There is a non-established link, a strong suspicion pyrite increases weathering and therefore lowers the heat content faster.

WEWERKA: There have been some studies done on the change in properties in coals with storage. In general the surface oxidation of organic material and the evolution of things like carbon monoxide usually begin to occur quite quickly after exposure to the elements, like in a period of weeks or so.

There is often some substantial loss of heat content over a . . . say a year. You can lose up to 10 percent of the heat content of the coal from oxidation and degradation during storage. There is also a change in things like agglomerating properties, and what have you; but it is not clear what effect differences in mineral matter would have on that process. I rather doubt whether change in pyritic content, for example, would appreciably change the rate of organic material degradation with the exception of the particle size effect. If you crush it down very, very small during cleaning, smaller than you might normally for shipping to the consumer, in an unclean state, then you could indeed increase the rate at which some of these processes occur and agglomerate again before you ship and store the material.

MR. DAN HUNTER, PHILLIPS PETROLEUM COMPANY: The first set of numbers for the combustion products of the Battelle process showed that nitrogen oxide emissions increase 20 percent. Is this something that can be attributed to the process?

STAMBAUGH: At this time we don't know the effect of our treatment process on the formation of NO_x. We do know that the process doesn't extract any of the nitrogen. The data on NO_x and flue gases has been quite scattered so we don't have a good handle on it yet. The nitrogen compounds in the coal seem to be quite stable. I can't see that the treatment process would have much effect on it.

KILGROE: I think, also, the data are taken from one or two pound combustors and the combustion configuration probably will not give you reliable data if you try to scale up to a large size combustor. We are going to do some combustion studies on multi fuels and, I guess, on some other boilers so as to get a better handle on NO_x emissions.

HUNTER: I didn't get the numbers from that chart. Was that a significant difference in flame temperature in the two cases?

STAMBAUGH: There may have been. I don't recall, but in most cases the flame high temperatures or the wall high temperatures varied from about 1,700 up to about 2,000 degrees. But whether or not, in that particular example, the flame temperature was different, I don't know.

MCCARTHY: Any other question from the floor? Mark Levine, maybe you have a comment on the use of your slide?

(EDITOR'S NOTE: In an aside from his formal paper presentation, R. E. Hucko, of the Bureau of Mines, screened a slide from Levine's talk showing U.S. Coal Cleaning By Region (Figure 1.1.12). Hucko then pointed out how easy it is to misinterpret the data on the percent of different coals meeting EPA SO_2 emission standards before and after cleaning.)

LEVINE: Thank you. I want to comment on Mr. Hucko's comment on our analysis. It is true we did not correct for weighted average sampling, primarily because we couldn't, based on existing data, or couldn't have done it very accurately. And it didn't look, as we looked at the data, as though it would make very much difference. In fact, I looked at Mr. Hucko's results and discovered his analysis for Northern Appalachia, in which he did a weighted analysis, came out not very different from the arithmetic mean.

It turns out there is a difference of a factor of 3 on the arithmetic numbers, the ones we use between coals "before" and "after" washing—the percentage of coal that meets EPA standards. There was a factor of 2.8 in his data. The numbers change, if you remember the numbers on the slide, from 4 and 12 percent taken from the U.S.B.M. report, to 2.5 and 7 percent if you work back from his data. The more important point, however, is that the purpose of the analysis was to indicate in general terms what coal cleaning could do.

What is important might be whether or not it might be needed, if you consider all the uncertainties involved in the analysis. The uncertainty associated with knowing exactly what the sulfur content of coal by regions is, is just one of many factors. I would also point out we don't really know if the washability studies are very good simulations of what would happen in a commercial plant. We'll know more about that when there are more commercial plants. Basically, I don't think the conclusions change much. In fact, as we were doing the analysis, we asked the question if it mattered very much.

The biggest region to be concerned about would be Southern Appalachia. If we changed the percentages from 35 and 50 percent for before and after coal cleaning—the percentage of coal that meets standards— to say 20 and 40 percent, it makes a difference in the analysis of .25 quadrillion Btu out of a total of 2.5 quadrillion Btu. So basically, the analysis is terribly sensitive to that. None the less, he's right. You want to do as well as you can. In fact there is a real need to do an analysis at the regional level, as has been pointed out, using U.S.B.M. data.

If I were going to build a coal plant, I would be very certain I did my analysis on the specific coal—samples of specific coal beds and mines that I was going to purchase from. I hope that answers the general comment basically. It doesn't matter too much in terms of the general analysis we did. Did you want to make any further comments?

HUCKO: Perhaps a quick comment would be appropriate. I think you took my gesture too much to heart. I was not indicting you nor your analysis in any way. I was indicting us for presenting misleading data. That was the purpose of my gesture.

LEVINE: There is an interesting point. I think the Bureau of Mines did by far the best analysis of sulfur content of coal. If they hadn't done the work there wouldn't be anything, essentially. It is useful for them, for anyone taking that kind of data, to ask how they would be used. I think Mr. Hucko pointed out that if those data could be presented in such a way that one could go from that information to more generalizable information about coal in the region, it would make it more useful for purposes of analysis.

HICKEY: I think this developing some sort of analytical methodology to try and get a grasp on this problem is extremely important. We can always use improvement in the way we have been doing it. I think we have an excellent start on this, with the PEDCo Report. This, with the PEDCo Report and from what I've heard today, sounds like we are getting steam up. It is so important to recognize quantification of data—of transportation. We have to have customers for one thing. We just can't say that in a region we have different controls and have to do things in such and such a way.

We have to have customers, industrial customers, residential customers . . . there have to be distribution and transmission costs. You're talking about siting plants; the transportation cost is part of it. Then water is a question. Do you ship wet or dry? Do you simply put newly installed cleaning units at a mine mouth facility or are we talking about cleaning plants at the site of the steam plants?

It seems to me since the Federal Power Commission can get all the steam power plants in one book—we really aren't talking about an infinite set of things—that really it wouldn't be too much to think of, possibly, to take a case by case analysis of these, rather than treating them in big groups or in regions. This, I think, to get started, provides an initial perspective on what the possibilities are. That's fine and dandy, and necessary. We have to have it, but maybe sometime down the road every single case must be taken into consideration. Of course, I can't take into consideration plants that haven't been sited yet; but, since we can put together a report on this like the FPC does every year, it wouldn't be too formidable to develop viable methodology on a case by case basis around the country and really have some competence with our strategy development.

LEVINE: I agree. Some work has been done along that line. There is a Schaeffer and Roberts Report out that looked at coal cleanability in regions of Pennsylvania, and looked both at cleanability and also primarily economics. FEA is gathering data on existing coal by sulfur content, by use in electric generating facilities in Ohio. It is my understanding EPA at Research Triangle Park and the enforcement people are gathering similar data for Ohio. So, I think the renewed interest in coal cleaning is seen also in the renewed interest in gathering data that can give us some idea of what sort of strategies we should use.

We've barely begun to look at those problems. I think my colleague, Jerry Issacs, is one example of having done an unusual study in the sense he looked carefully at the economics. Homer City is another case. So it is started. But there hasn't been nearly enough, certainly not at the policy level, in terms of encouraging strategies. For example, I don't know the details, but I know Homer City applied to EPA for some changes in regulations such that less sulfur would be emitted to the air at a lower cost to DPU and lesser degradation to the environment. EPA, as far as I know, rejected the change in regulations. I'm not sure if I have that story entirely straight.

MCCONNELL: We suggested that some consideration be given, rather than controlling each unit, to control the site; and thereby optimize the coal supply on the basis of the Homer City site. You can certainly accomplish equal or better environmental protection for less dollars, but it does tend to circumvent the spirit of implementation of the Clean Air Act.

However, in deference to my customers, of which I am one, I still want to see the least cost solution. They really couldn't do that at Homer City.

KILGROE: A few comments on the EPA point of view. I think they looked at the material we got at DPU. The decision was that it would reduce costs and create certain regulatory problems. I am speaking from a researcher's point of view and not the regulatory side of the house; but they, I guess, turned down that request for that reason. As far as reduced environmental impact, there would have been the same, I believe, total sulfur emissions from the site. The fact they were using a higher stack on unit number three would have reduced a salient factor in air quality, so the air quality in the inner region probably would have been improved somewhat by using dirtier, sulfurwise, coal in the unit number three. The emissions would be dispersed over a larger area. That's where you get the statement it would reduce the environmental impact.

PHUNG: I would like to comment on the gentlemen's suggestion of all the data of coal mines and coal facilities be put in one book like the FPC book. I think that is quite a formidable task. The FPC does have a book that puts all power plants in it. It is now two years late. It is now 1976 and we don't have 1974 and 1975 data yet. It seems to me that half of the activity of the FPC is devoted to that book, and it represents many, many millions of dollars. So unless any agency in the country has a new mandate, maybe from Congress, to do that kind of activity, it is a formidable task.

HICKEY: I was using the suggestion that they get all the on-stream plants in one book just to illustrate what we are dealing with. We have a number of plants that add up to the whole; and only by treating these as individual cases can we come up with any strategy, with a developed methodology for doing analysis. You have gotten started in two different directions at least. I don't see these published as a policy in a book every year. I am suggesting we develop strategies that are more realistic so we avoid the pitfall of drowning in two feet of water by using large scale, large regional averages that ignore specific plants' circumstances in factors of that nature. Transportation is one of the big ones and may be overriding in some cases. The other minor complications, such as existing contracts, are a real fact. You have to begin to see what actually is the situation at each individual plant at any time when you do the analysis. I would suggest publishing a book saying, "Here are all the answers."

ISSACS: You put emphasis on treating plants on an individual basis. Then are you saying that we shouldn't take into account the other plants around there, that you treat these one plant at a time? I don't understand why you're on a plant by plant basis rather than a group of plants together.

HICKEY: I guess the thing that triggers me is, in using this, is that we say we have so much coal in the Appalachian area; and it can be treated to remove so much sulfur at a certain level. I think there is great danger in this because of the variability of coals, the variability of organic and inorganic fractions of these coals, the differences in the ash characteristics in these coals, the operability in existing boilers. There isn't any question we can answer here today. As Jim (Kilgroe) says, try it and be sure when you make a statement that is in a given area, say Pennsylvania, there is a certain amount of coal that can be economically treated by Process "X". I just wonder if we are being realistic.

LEVINE: I was talking to John Fink, of EPA at Research Triangle Park. I'm going out there to see him because of a statement he made to me that the FPC and EPA data bases have been merged, and all the environmental information that EPA has on individual plants is combined in a single data base with the information the FPC has. They both work off the same data base system. Now I don't know any more about it than that. The reason I am going back is in response to the sort of interest Mr. Hickey expressed: that is, we are trying to analyze alternative environmental control strategies. Hooking up with realiable data bases is one of the things we have to do.

MCCARTHY: Some comments from Sam.

ALTSCHULER: I was a late substitute to this symposium and as a result I was not able to present much for publication, as the proceedings will be coming out in a few weeks. However, people have asked about copies of the data I presented. I would like to mention that the U.S.G.S. has recently completed an assemblage of analyses of many, many hundreds of coal samples collected from about 3,000 samples which embrace trace element analyses, of ash, coal, Btu values, sulfur determinations collected by the Bureau of Mines. All of this is part of a very comprehensive data bank—this is rather pertinent to the discussion here—that the survey is maintaining for the national interest in coal. This data bank will include data on structure and stratigraphy, ash content, trace element content. It is entered in a computer which has the capacity for mapping and contouring the data and superimposing it on all different scales according to all national scale bases. We hope eventually to be able to contour such things as individual trace elements in the ground, thickness of coal, associations between thick coals, associations between trace elements, Btu, etc. Some of this raw data, not the computerized output, are available in what we call an "open file report."

I mention this because I am apologetic that I won't be able to publish much of that data I presented in your proceedings. Our open file system consists of reports made available at three survey repositories—Denver, Washington, D. C., and Menlo Park. The open file report is called "Collection, Chemical Analysis and Evaluation of Coal Samples 1975." It's number is 76-468. It is published by the U.S. Geological Survey, Thank you.

KILGROE: It's getting late. I think everyone probably would like to go home. Don't you think so, Bill?

MCCARTHY: I'm always one to take advantage of an opportunity. Therefore, I have kept this expertise assembled for longer than scheduled; but you're right. Thank you for coming gentlemen. The session is adjourned.

APPENDIX

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ABOUT THE AUTHORS

ALTSCHULER, SAMUEL Z. is studying the origin and distribution of low sulfur coals by mapping and geo-chemical investigations for the U.S. Geological Survey, Reston, Va. A U.S. Geological Survey employee for 25 years, he has been involved in phosphate geology and uranium geo-chemistry research, analysis and evaluation. He has degrees from Brooklyn College and the University of Pennsylvania.

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LEVINE, MARK D. is with the Center for Environmental Systems at Stanford Research Institute, Menlo Park, California. He recently completed a status report on coal cleaning for the U.S. Environmental Protection Agency. He also has done work for the Federal Energy Administration, National Science Foundation, and American Electric Power Association. He is a graduate of the University of California, Berkeley.

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METRIC CONVERSIONS

To Convert From	To	Multiply by
Btu/hour	watt (W)	2.93077 E−01
Btu	joule (J)	1.055056 E +03
calorie	joule (J)	4.19002 E +00
centimeter of Hg	pascal (Pa)	1.33322 E +03
centipoise	pascal (Pa·s)	1.000 E−03
degree centigrade	degree kelvin (k)	$t_k = t_c + 273.15$
degree Fahrenheit	degree celsius	$t_c = (t_F - 32)/1.8$
foot	meter (^{m})	3.048 E−01
ft³/sec	meter³/sec	2.831685 E−02
gallon/min	meter³/sec	6.309020 E−05
inch	meter (m)	2.54 E−02
kWh	joule (J)	3.6 E +06
month	second (s)	2.628 E +06
lb/in²	kilogram/meter²	2.926397 E−04
lb/in³	kilogram/meter³	2.76799 E +04
psi	pascal (Pa)	6.894757 E +03
ton (assay)	kilogram (kg)	2.916667 E−02
tonne	kilogram (kg)	1.0000 E +03
year (calendar)	second (s)	3.1536 E +07